UPGRADING NOVA SCOTIA OIL SHALE FOR POTENTIAL USES

UP - N - 190

Principal Investigator: M.C. Rockwell
Dept. of Mining & Metallurgical Engineering, Technical University of Nova Scotia.

DSS File Number : 24 St. 23440-4-9267
Contract Serial Number : 1ST84-00382
EMR/CANMET Scientific Authority : Mr. L. Janke

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MICROMEDIA

TABLE OF CONTENTS

	page
1. INTRODUCTION	1
1.1 Background	1
1.2 Overview on Oil Shale Processing	2
1.3 Objective of the Study	5
2. SUMMARY	6
3. CONCLUSIONS	8
4. RECOMMENDATIONS	10
5. EXPERIMENTAL WORK	11
5.1 Samples Collection and Preparation for Analytical Determinations	11
5.2 Oil Shale Characterization	15
5.2.1 Properties and Geochemistry of Oil Shale	15
5.2.2 Mineralogy	22
5.3 Processing and Upgrading Oil Shale Zone C	25
5.3.1 Rational for Selecting Zone C Oil Shale	25
5.3.2 Sample Preparation for Testing	25
5.3.3 Heavy Liquid separation Tests	28
5.3.4 Wilfley Table Separation Tests	29
5.3.5 Conventional Flotation Tests	31
5.3.6 Oil Agglomeration/Brine Flotation Tests	31
6. RESULTS AND DISCUSSION	33
6.1 Heavy Liquid Separation	33
6.2 Wilfley Table Separation	36

6.3 Conventional Flotation 38

6.4 Oil Agglomeration/Brine Flotation 38

6.5 Characteristics of Upgraded Oil Shale Zone C 52

7. REFRENCES 56

8. ACKNOWLEDGEMENTS 59

9. APPENDICIES

A1. Thermal Analysis of Oil Shale Zones 60

A2. Hydrocarbon Profile of Oil Shale Zones 90

A3. Hydrocarbon Profile of Upgraded Oil Shale Zone C 97

LIST OF TABLES

Table No.	Title	page
1	Qualitative Element Identification of Oil Shale by SEM/EDX Analysis.	17
2	Proximate Analysis of Oil Shale.	18
3	Composition and Calorific Value of Oil Shale.	18
4	Major Oxides Composition of Oil Shale.	19
5	Minor and Trace Elements of Oil Shale.	19
6	Fischer Assay of Oil Shale.	20
7	Composition and Calofific Values of Shale Oil.	20
8	Proximate Analysis of Spent Shale.	21
9	Rock-Eval Pyrolysis of Oil Shale.	21
10	Grinding Tests Particle Size Distribution, Zone C.	26
11	Heavy Liquid Separation Tests.	34
12	Wilfley Table Separation Tests.	34
13	Frother Comparison Tests-Conventional Flotation.	39
14	Effect of Flotation Time-Conventional Flotation.	39
15	Oil Agglomeration/Brine Flotation Tests.	41
16	Proximate and Ultimate Analysis of Upgraded Oil Shale Zone C.	53
17	Ash Analysis (Major Oxides) of Upgraded Oil Shale Zone C.	53
18	Fisher Assay of Upgraded Oil Shale Zone C.	54
19	Analysis of Oil Recovered from Upgraded Oil Shale Zone C.	54
20	Proximate Analysis of Spent Shale (Concentrate and Tailing).	54

LIST OF FIGURES

Figure No.	Title	page
1.	Area Underlain by Oil Shale Pictou County Deposit.	12
2.	Deposition & Sampling of Oil Shale Zones at L.E. Shaw Ltd., Clay Open Pit, N.S.	13
3.	Oil Shale Storage, Flushed with Nitrogen.	14
4.	Thin section of Oil Shale Zone E and Zone A Parallel to the Bedding Plane, Magnification 100X.	23
5.	Thin Section of Oil Shale Zone B and Zone C Parallel to the Bedding Plane, Magnification 100X.	24
6.	Cumulative Diagram of Oil Shale Zone C Screen Analysis.	27
7.	Wilfley Laboratory Table and Wemco Fagergren Flotation Cell used in Tests.	30
8.	Effect of Liquid Density on Carbon Recovery and Grade for Fractions -600 +250 and -250 +150 Microns.	35
9.	Effect of Particle Size on Carbon Recovery and Grade (Wilfley Table Separation).	37
10.	Effect of Brine Concentration on Carbon Recovery and Grade in Oil Agglomeration/Brine Flotation.	43
11.	Effect of Amount of Kerosene on % Carbon Recovery and Grade in Oil Agglomeration/Brine Flotation.	44
12.	Flotation time Versus Carbon Grade and Recovery for Conventional Flotation and Oil Agglomeration/Brine Flotation.	46
13.	Simplified Flowsheet for Oil Shale Upgrading by Oil Agglomeration/Brine Flotation.	48
14.	Oil Agglomeration/Brine Flotation Feed and Cleaner #1 Concentrate, Magnification 100X.	49
15.	Oil Agglomeration/Brine Flotation Final Concentrate, Magnification 200X.	50
16.	Effect of Multi-Stage Cleaning of Rougher Concentrate.	51
17.	Relationship Between Organic Carbon and Oil Yield of Sampled and Upgraded Zone C Pictou Oil Shale.	55

1. INTRODUCTION

1.1 Background

Nova Scotia has an appreciable resource of low grade oil shale. Two major deposits of oil shale are located in Pictou and Antigonish Counties. The possible upgrading and development of this resource could make the province less dependent on imported crude oil and would provide a stimulus to the local economy.

Approximately 72% of Nova Scotias primary energy requirements is derived from imported crude oil, of which over 50% is from foreign countries while the remainder comes from Canadian sources (1). The province could be placed in a vunerable position in the event of an import supply disruption and lack of available alternate fuels such as natural gas.

Over the past decade, many countries of the world have placed considerable interest in utilizing oil shale as a local energy and chemical source. In the Soviet Union, oil shales find commercial use in fired thermal power stations and in the manufacture of over 40 shale oil based products, such as: coke for carbon electrodes, oil for wood impregnation, waterproof mastics, chemicals for soil conditioners, rubber modifiers, adhesives, resins for sand consolidation in oil and gas wells, etc. (2,3,4).

The oil shale occurances in Nova Scotia have been known for many years. Prior to 1929, an oil shale mine and two retorting plants were operating in Pictou County; but the economics of the Great depression forced their closure. Since then there has been little interest in the oil shale potential and the investigation of this resource has been inconsistent.

In 1980, the previous work was reviewed and further documented (5,6,7). More recently, the Federal Government and the Nova Scotia Government have initiated a common program to assess, map and evaluate the economic geological potential of the major oil shale deposits in Nova Scotia.

1.2 Overview on Oil Shale Processing.

The extraction of the oil and/or gas products from oil shale is accomplished conventionally by thermal retorting. This requires that the shale be heated to approximately 480°C or higher. Heat may be supplied by either direct or indirect means. To retort one ton of oil shale requires approximately 630 to 840MJ (8).

Because retort production is limited by rock mass handling capability rather than by oil production capability, a considerable saving in retort capital and operating cost may be achieved if much of the ash forming minerals are rejected prior to retorting.

In their investigations, Hanna, H.S. and C. Rampacek (9) favored physical beneficiation followed by retorting of the upgraded product. The cost of retorting an upgraded product yielding 18 to 20 gal/ton oil was reported at $33. per barrel of shale oil. This realized a cost saving of approximately 20% over retorting the raw oil shale containing 12.5 gal/ton oil yield.

Physical concentration techniques have been extensively applied and investigated for mineral and coal processing; but only modest research efforts have been expended for processing oil shale.

Different shale rock components vary significantly in physical and surface chemical properties, such as: specific gravity, color, toughness, water wetability, etc. Various techniques that use the difference in one or more of these properties have been proposed to separate the organic phase, kerogen, from the inert mineral phases (9-27). These techniques usually involve crushing, grinding, screening and several subsequent concentration stages.

The trend of approach in research to upgrade the U.S. Eastern oil shale has been to grind the oil shale to 80% passing 20 microns, and in some instances 90% passing 10 microns, followed by froth flotation under various conditions (10-20). Grinding the shale to such fine mesh sizes with a conventional ball mill has been estimated to require in excess of 45 KWh/ton

shale, and approximately 26 KWh/ton shale using a high speed ball mill (11,14).

Due to the complex nature of the low grade oil shales, difficulties to consistently produce a high grade of concentrate at a high percentage recovery by conventional froth flotation still exists (10-20). A maximum recovery of approximately 53% and a 27 gal/ton oil was obtained by froth flotation of an oil shale containing 10-11 gal/ton oil. At a recovery of 89% the grade decreased to approximately 13 gal/ton oil (13,14). The same raw shale ground with 1.5 lb/ton kerosene produced a flotation concentrate containing 35 gal/ton oil with a recovery of 60% (14).

The recent publised attempts for processing the Kentucky low grade oil shale involved hot grinding (80°C) to 90% passing 10 microns, followed by froth flotation stages combined with an ultrasonic dispersion of the shale slurry (15). This method upgraded an oil shale containing 14 gal/ton oil to 33.6 gal/ton oil with a 65% recovery.

Nova Scotia oil shale has some common similarities with the U.S. Eastern oil shale; however, it is known that shale from different deposits have widely variable properties. This variability limits the applicability of a single upgrading process to efficiently treate all types of oil shale deposits.

1.3 Objectives of the Study.

The objective of the current study is to conduct a preliminary investigation into the technical feasibility of physical processing and upgrading Nova Scotia Pictou oil shale for potential uses. In support of this objective, four different exposed oil shale zones from the Pictou oil shale deposit were trenched and sampled. Approximately 100kg of bulk samples were collected from each zone. Representative samples were prepared for extensive characterizations, section 5.2. The lowest oil yield zone sample was subjected to processing and upgrading by physical beneficiation methods. The sample was sized into five fractions and processed by heavy liquid separation, tabling and flotation techniques. Chapter 6. discusses the results.

2. SUMMARY

Oil shales in Nova Scotia are found at various locations on the mainland and on the island of Cape Breton. Two major oil shale deposits are located in Pictou and Antigonish Counties.

The oil shales studied in this report are sampled from four exposed zones of the Pictou deposit. The shales are of a silicious nature and have an oil yield content ranging from 5.0 gal/ton to 19.8 gal/ton, Fischer assay.

The study reveals that the high grade oil shale of 19.8 gal/ton could be separated by screening techiques into fractions of oil yields ranging from 12 gal/ton to 24 gal/ton. The higher yields could be used as a retort feed, whereas the lower yields could be used in thermal power generation or for further upgrading.

The study concentrated in upgrading oil shale from a zone with 5.0 gal/ton by mineral processing techniques. Five size fractions were tested using the Wilfley table, heavy liquid separation, conventional flotation and oil agglomeration/brine flotation. The fraction -600 +150 microns responded positively to the heavy liquid separation and the fraction -45 microns to the oil agglomeration/brine flotation. This indicates a feasibility to initially upgrade or preconcentrate the shale at a coarser fraction prior to the treatement by flotation

techniques. It was possible to obtain an oil yield exceeding 16 gal/ton, (Fischer Assay), by using an oil agglomeration/brine flotation technique.

3. CONCLUSIONS

Four different exposed zones from the Pictou oil shale deposit were sampled and subjected to an extensive characterization. The oil shales are of a silicious nature, approximately similar to the U.S. Eastern oil shale. The oil yield content ranges from 5.0 gal/ton to 19.8 gal/ton.

The oil shale zone with the lowest oil yield was selected for upgrading by various size fractions using heavy liquid separation, tabling, conventional flotation and oil agglomeration/brine flotation. The major conclusions derived from this research are:

1) The oil shale size fraction selected for processing is critically important to achieving high concentrate grade and recovery.
2) Concentrate grade and recovery are sensitive to variations in slurry density.
3) The oil shale size fractions -600 +250 and -250 +150 microns responded positively to heavy liquid separation indicating that an initial separation of a mined shale could be possible.
4) The selectivity and efficiency of the Wilfley table was improved by using a ground glass surface and 5° angle riffled arrangement. However, only the size fraction -150 +75 microns resulted in a better separation. This

will limit the application of the tabling process on oil shale similar to the zone tested.

5) Conventional flotation selectivity response of fractions -75 +45 microns to three types of frother was poor. An increase in flotation time and using only the fraction -45 microns samples did not significantly influence the quality of separation.

6) The oil agglomeration/brine flotation is sensitive to the type and amount of collector, brine concentration and flotation time.

7) The oil agglomeration/brine flotation of zone C was performed on 100% passing 45 microns and produced a better upgrading performance than the 80% passing 20 microns and 90% passing 10 microns of the U.S. Eastern oil shale processed by other methods.

8) This study demonstrated the technical feasibility of upgrading the low grade oil shale by size fractions, using various physical beneficiating methods and testing their performance under various conditions.

4. RECOMMENDATIONS

The research carried out in completing this project identified the following areas for further investigation:

1) Determine the amenability of the upgraded product to the retorting process.
2) Investigate oil agglomeration/brine flotation on other grades of oil shale.
3) Investigate the effect on the physical structure of the kerogen particles of conventional grinding versus other methods of liberation.
4) Identify the changes in the chemistry of shale (clay) during wet grinding and flotation of oil shale.
5) Study the effect of various reagents in reducing the hydrolysis of clay during the processing of shale.
6) Investigate the types of heavy media fluid and the separation efficiency at various mesh size fractions.
7) Investigate the feasibility of utilizing upgraded oil shale in fluidized bed combustion with coal.
8) Investigate fragmentation techniques and the fragmentation characteristics of oil shale.
9) An extensive characterization of a larger number of oil shale samples should be undertaken.
10) Investigate the amenability of agglomerated oil shales to the retorting process including agglomeration techniques and binders for fine upgraded products.

5.0 EXPERIMENTAL WORK

5.1 Sample Collection and Preparation for Analytical Determinations.

The oil shale samples were collected from exposed zones of the Pictou oil shale deposit at the L.E. Shaw Ltd. open pit clay operation, near New Glasgow, Nova Scotia, Figure 1. The area was cleaned of surface contamination and the heavily oxidized material on the face of the oil shale zone was removed with a backhoe. The backhoe cut a nine by three foot wide trench across the four exposed oil shales zones marked for convienence as zone A, B, C and E, Figure 2. The back of the trench was sample channeled by hand and pick.

Approximately 100kg of sample was collected from each zone. The samples were air dried, weighed, crushed to 4.75mm and split into four quarters. Three quarters were stored in air tight containers for further processing. The remaining quarter was crushed to 2.36mm and stored in separate containers under vacuum and flushed with nitrogen, Figure 3. Representative samples were prepared for analytical determinations from each crushed 2.36mm product following the procedure in the ASTM D 2013 "Standard Method of Preparing Coal Samples for Analysis".

Additional representative samples were prepared from a composite sample marked D, and from four size fractions of sample zone

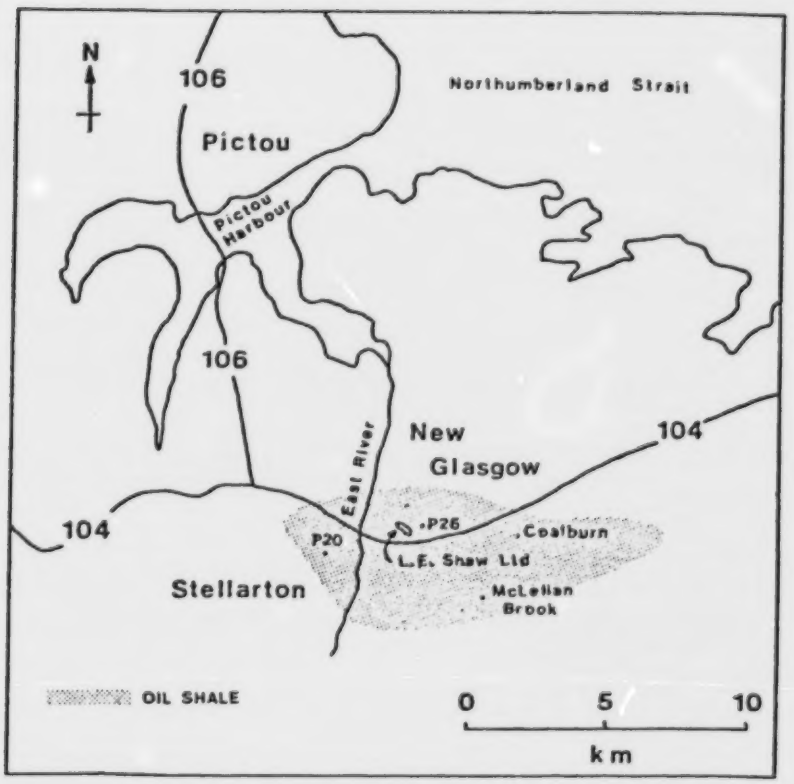


Figure 1. Approximate area underlain by Pictou County oil shale deposit.

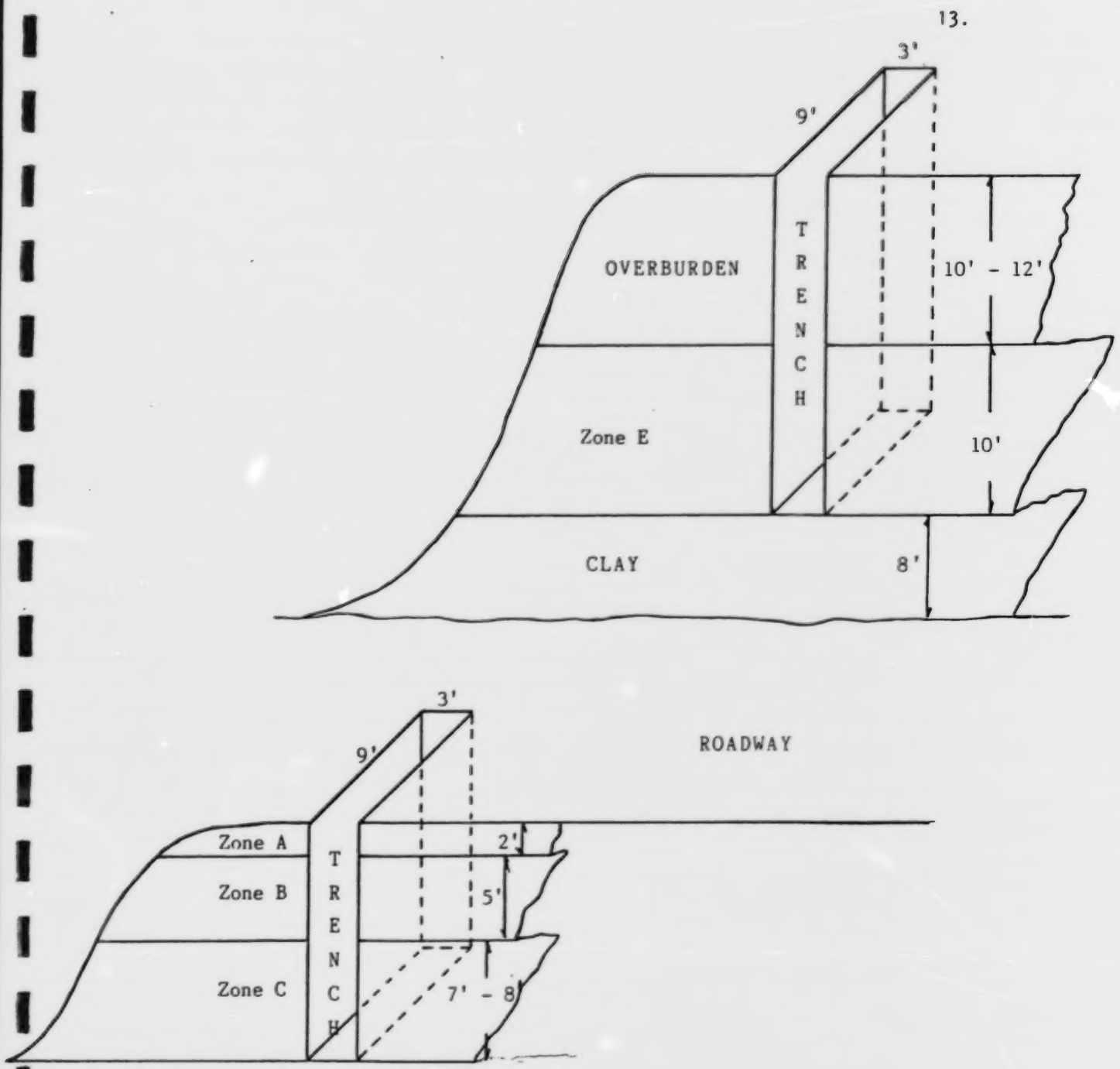


Figure 2. Deposition & Sampling of Oil Shale Zones at L.E. Shaw Ltd., Clay Open Pit, N.S.

Figure 3. Oil Shale Storage, Flushed with Nitrogen.

B. The composite oil shale sample D was made from riffled out equal parts of 2.36mm crushed sample zones A, B and C. The four size fractions of sample zone B were designated BB1 (-250+150), BB2 (-150+75), BB3 (-75+45) and BB4 (-45) microns.

5.2 Oil Shale Characterization

5.2.1 Properties and Geochemstry of Oil Shale

Representative analytical samples of four oil shale zones and selected size fractions were subjected to physical and chemical analysis, Fischer assay, thermal analysis, Rock-Eval pyrolysis and non-destructive analysis. The shale oil recovered from the Fischer laboratory retort was analysed for its calorific value, elemental composition and hydrocarbons profile.

Approximately 500g of representative sample passing 250 microns sieve was sent to the Research productivity Council, Fredericton, N.B. for a complete analysis and Fischer assays, and to the Dunlop Research Center, Mississauga, Ont. for thermal analysis. The extracted oil from the Fischer laboratory retort was sent to Core Laboratories, Canada Ltd., Calgary, Alberta for extended analysis of the hydrocarbons profile to C 30+. The non-destructive analysis and a Rock-Eval pyrolysis test were performed by the Atlantic Coal Institute, Cape Breton, N.S.

The non-destructive analytical determination of the shale included energy dispersive X-ray analysis (EDX) and SEM analysis using a JEOL T 300 scanning electron microscope. The results are presented in Table 1 and are summarized from the ACI Report 85-154. The major element identifications by EDX analysis are: Si, Al, K and Fe for all four sampled zones. The scanning electron microscopy revealed a lack of porosity in all shales.

The physical and chemial analysis performed by RPC followed the recommendation stated in the statement of work of the contract and the procedure outlined in the ASTM Annual Book of Standards, 1984, section 5. Tables 2 to 5 tabulate the results of the properties and composition of oil shale from these analysis. The oil shale samples are characterized by high silica and alumina content, low carbonates and low sulfur and nitrogen content. The highest percentage of organic carbon is contained in sample zone B followed by sample zones A and E. Sample zone C contains the least organic carbon. Ash content varies from 70% to 86%. The Fischer assay of oil shales results are given in Table 6. The Fischer assay of sample zone C has the lowest oil yield at 5.0 gal/ton as compared to 19.8 gal/ton for sample zone B.

The elemental composition and calorific values of the oil recovered from the Fischer retort is presented in Table 7, and the proximate analysis of spent shale in Table 8. The results from Rock-Eval pyrolysis, Table 9, show higher yields

Table 1. Qualitative Element Identification of Oil Shale by SEM/EDX Analysis.

Sample	Major Elements	Identified Minerals	Unidentified Material	Notes
A	Si, Al, K, Fe	illite quartz pyrite kerogen monazite siderite	dioptase (?) FeCu silicate	pyrite and FeCu octahedra
B	Si, Al, K, Fe	illite quartz pyrite kerogen	iron silicate	detrital quartz pyrite octahedra organic casts relics
C	Si, Al, K, Fe traces of Ba or Ti	illite quartz gypsum halite	Fe-Cu silicate	elongate grains illite flakes halite/clay balls
E	Si, Al, K,	illite pyrite barite	K feldspar (?) pseudomorph FeCu silicate	petrified organic

Table 2. Proximate Analysis of Oil Shale (wt.%).

Sample	Moisture	Ash	Volatile Matter	Fixed Carbon
A	0.67	83.43	11.8	4.1
B	0.63	70.18	18.6	10.6
C	0.74	86.17	9.7	3.4
D	0.72	79.97	12.9	6.4
E	0.51	82.85	12.5	4.1
BB-1	0.93	68.71	18.2	12.2
BB-2	0.96	68.18	20.4	10.5
BB-3	0.99	70.92	17.9	10.8
BB-4	0.85	72.60	16.0	10.6

Table 3. Composition and Calorific Value of Oil Shale (wt.%).

Sample	Organic Carbon	Mineral Carbon	H	N	O	S	(BTU/lb)
A	9.44	<0.5	1.66	0.60	4.40	1.06	1472
B	21.41	1.1	2.81	0.83	2.54	1.10	3935
C	6.99	<0.5	1.45	0.50	4.18	0.48	1021
D	12.91	<0.5	1.95	0.66	3.5	0.84	2129
E	7.08	1.1	1.59	0.52	6.32	0.57	1074
BB-1	24.04	<0.5	2.69	0.81	2.39	1.14	4119
BB-2	23.44	0.9	2.51	0.90	2.95	1.14	4135
BB-3	21.14	<0.5	2.38	0.79	3.28	1.14	3788
BB-4	19.70	<0.5	2.15	0.78	3.35	1.18	3513

D - Blend of A, B and C
BB - Mesh fractions of B

Table 4. Major Oxides Composition of Oil Shale (wt.%).

Sample	SiO2	Al2O3	Fe2O3	CaO	MgO	K2O	Na2O	TiO2	LOI
A	58.3	23.0	8.39	1.08	0.70	1.71	1.05	0.79	1.89
B	63.4	16.6	7.75	1.75	0.58	1.17	1.06	0.72	1.90
C	61.9	20.5	7.22	1.27	0.78	1.76	1.31	0.73	1.91
D	61.9	20.3	7.93	1.64	0.88	1.54	1.17	0.75	1.70
E	58.8	16.6	6.32	7.65	1.23	1.37	1.20	0.57	2.56
BB-1	63.7	16.5	8.36	1.97	0.68	1.19	0.92	0.60	2.32
BB-2	64.7	16.1	8.73	1.86	0.65	1.25	0.94	0.60	1.98
BB-3	65.2	16.4	8.18	1.90	0.68	1.14	1.14	0.60	1.75
BB-4	64.4	16.9	8.21	1.94	0.68	1.11	1.23	0.58	1.95

Table 5. Minor and Trace Elements of Oil Shale (ppm).

Element	A	B	C	D	E	BB-1	BB-2	BB-3	BB-4
Cu	46	45	48	47	37	47	46	50	61
Pb	46	49	55	63	41	54	56	58	52
Mo	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Co	20	18	19	20	17	18	19	19	17
Ni	53	42	50	50	43	41	43	44	43
Cr	106	91	111	124	95	83	80	81	86
Mn	1037	1714	910	1548	1135	1504	1348	1314	1509
Cd	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Ag	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
Bi	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0
As	15	<5.0	<5.0	<5.0	12	15	13	13	<5.0
Zn	153	155	167	181	130	150	137	142	150
V	125	99	128	135	94	102	101	99	100
Te	<10	<10	<10	<10	<10	<10	<10	<10	<10
U	69	109	75	146	52	110	84	100	136
W	20	29	23	37	23	29	21	22	27
Sb	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0
Se	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0	<5.0
Sn	<10	<10	<10	<10	<10	<10	<10	<10	<10

D - Blend of A, B and C
BB - Mesh fractions of B

Table 6. Fischer Assay of Oil Shale.

Sample	Water wt.%	Gas Lost wt.%	Oil wt.%	Density g/ml	Oil Yield Imp. gal/ton	Oil Yield gal/ton
A	1.6	0.9	4.5	0.8843	10.3	12.4
B	1.6	3.5	7.4	0.8950	16.5	19.8
C	2.1	2.0	1.9	0.8913	4.2	5.0
D	2.0	1.9	4.1	0.8783	9.3	10.2
E	1.6	1.4	2.0	0.8829	4.4	5.3
BB-1	1.0	8.1	4.4	0.8905	10.0	12.0
BB-2	2.0	2.7	8.8	0.8820	20.0	24.0
BB-3	2.1	2.3	7.1	0.8808	15.8	18.9
BB-4	2.2	4.5	4.8	0.8877	10.9	13.1

Table 7. Composition and Calorific Values of Shale Oil (wt.%).

Sample	C	H	N	O	S	Calorific Value BTU/Lb
A	86.96	11.90	0.88	<0.05	0.34	18333
B	86.35	11.38	1.03	0.94	0.30	18480
C	86.97	11.41	1.19	0.32	0.36	18467
D	82.88	11.12	0.64	5.02	0.34	
E	81.59	11.03	0.76	6.21	0.41	18444
BB-1	87.04	11.40	1.29	<0.05	0.29	18296
BB-2	83.94	11.50	0.94	3.32	0.30	18494
BB-3	84.22	11.33	0.85	3.33	0.27	18434
BB-4	85.62	11.37	0.98	1.75	0.28	18303

D - Blend of A,B and C
BB - Mesh fractions of B

Table 8. Proximate Analysis of Spent Shale (wt.%).

Sample	Moisture	Ash	Volatile Matter	Fixed Carbon
A	0.23	89.01	8.47	2.3
B	0.09	79.14	10.07	10.7
C	0.01	91.24	6.65	2.1
D	0.13	86.35	8.18	5.3
E	0.19	87.42	10.95	1.4
BB-1	0.04	78.50	8.46	9.0
BB-2	0.11	78.61	10.50	10.8
BB-3	0.06	79.96	9.32	10.7
BB-4	0.02	81.59	7.99	10.4

D - Blend of A,B and C
BB - Mesh fractions of B

Table 9. Rock-Eval Pyrolysis of Oil Shale.

Sample	T max (C)	S1(mg/g)	S2(mg/g)	S3(mg/g)	S1/(S1+S2)
A	450.00	1.41	34.45	0.89	0.04
B	450.00	5.13	143.28	0.75	0.03
C	450.00	1.50	19.90	0.68	0.07
D	452.00	2.77	74.05	0.59	0.04
E	451.00	1.86	20.19	0.93	0.08

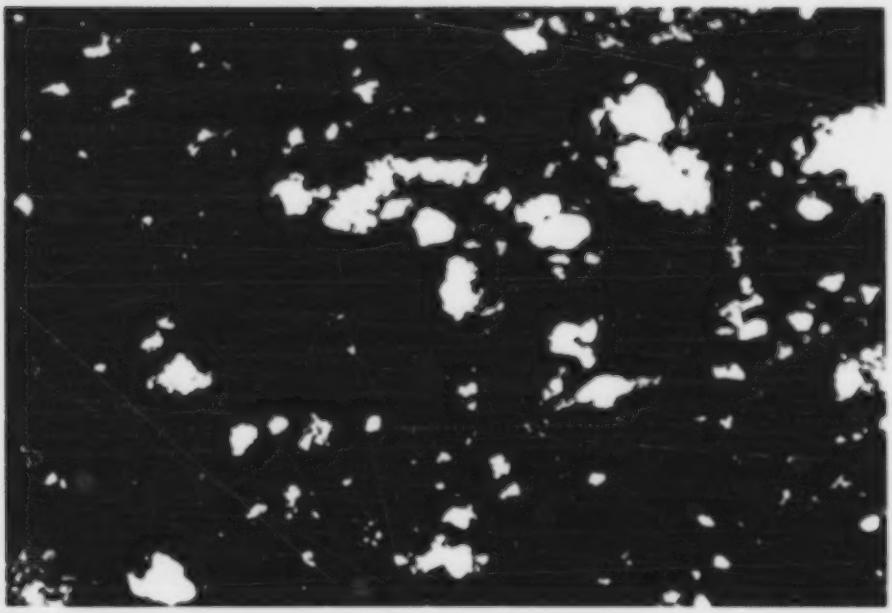
Girdel Rock-Eval MkII Pyroanalyser
Calibration by I.F.P. standard and Albert Mines Oil Shale (via I.S.P.G.)
I.F.P.: Tmax = 426, S2 =5.2, S3 = 1.8
A.M. 842: Tmax = 450, S2 = 110.0, S3 = 1.11, S1 = 8.0
Sample size: 30 mg

Tmax - Temperature index (degrees Celsius)
S1 - Free hydrocarbons (mg HC/g of rock)
S2 - Residual hydrocarbon potential (mg HC/g of rock)
S3 - CO2 produced from Kerogen pyrolysis (mg CO2/g of rock)
S1/S1+S2 = Hydrocarbon production index
D - Blend of A,B and C

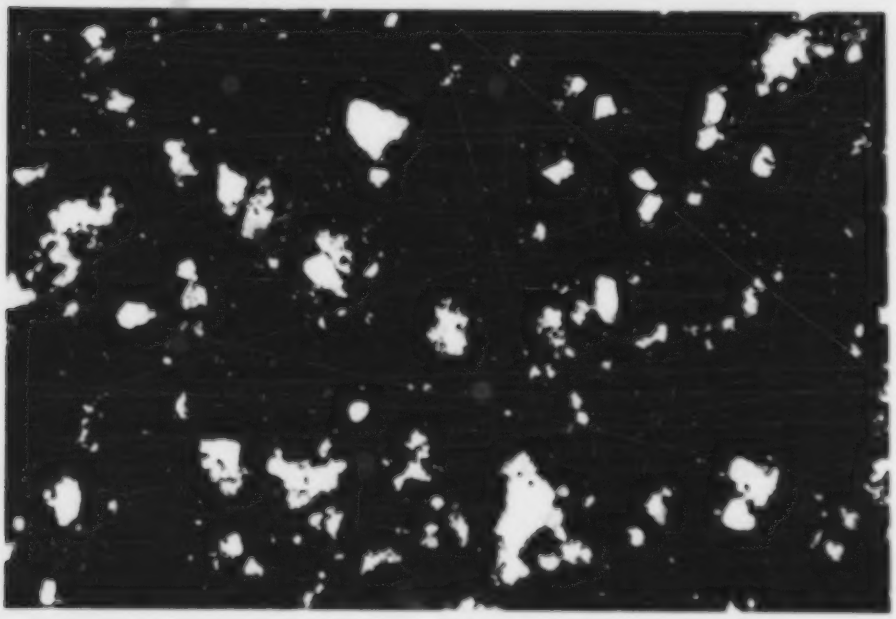
(S1 + S2), than Fischer Assay. Hydrocarbon profile to C 30+ of the Fischer retort shale oil for all samples except E (not significant) are attached in Appendix 1. Thermo gravimetric analysis (TGA) and differential scanning calorimetry (DSC) results are attached in Appendix 2. The thermal analysis results correlate with the proximate analysis in Table 2.

5.2.2 Mineralogy

Examination under transmitted light microscopy of thin sections of oil shale revealed subrounded to subangular quartz grains, feldspar and other silicates, of maximum 100 microns, in a matrix of extremely fine indefinite clay minerals. The kerogen occurs as gelatious coatings on the coarser detrital grains as well as string like concentrations and globules along laminae. The kerogen phase is discontinuous and displays four types of colors: 1) a dark brownish amorphous matrix intimately associated with clays and very fine grained detrital fractions characteristic to all samples, 2) a distinctive "red body" sapropelic kerogen predominately in sample zone B and to some extent in A and less in sample zone C, 3) "yellow body" sapropelic kerogen. In this instance displaying amorphous form but often as distinct body with spore like form, characteristic to sample B, A and C, 4) a brownish-red or yellow humic (herbaceous) kerogen of woody texture, predominately in sample zones C, E and A.



Zone E



Zone A

Figure 4. Thin Section of Oil Shale Zone E and Zone A Parallel to the Bedding Plane. Magnification 100X.

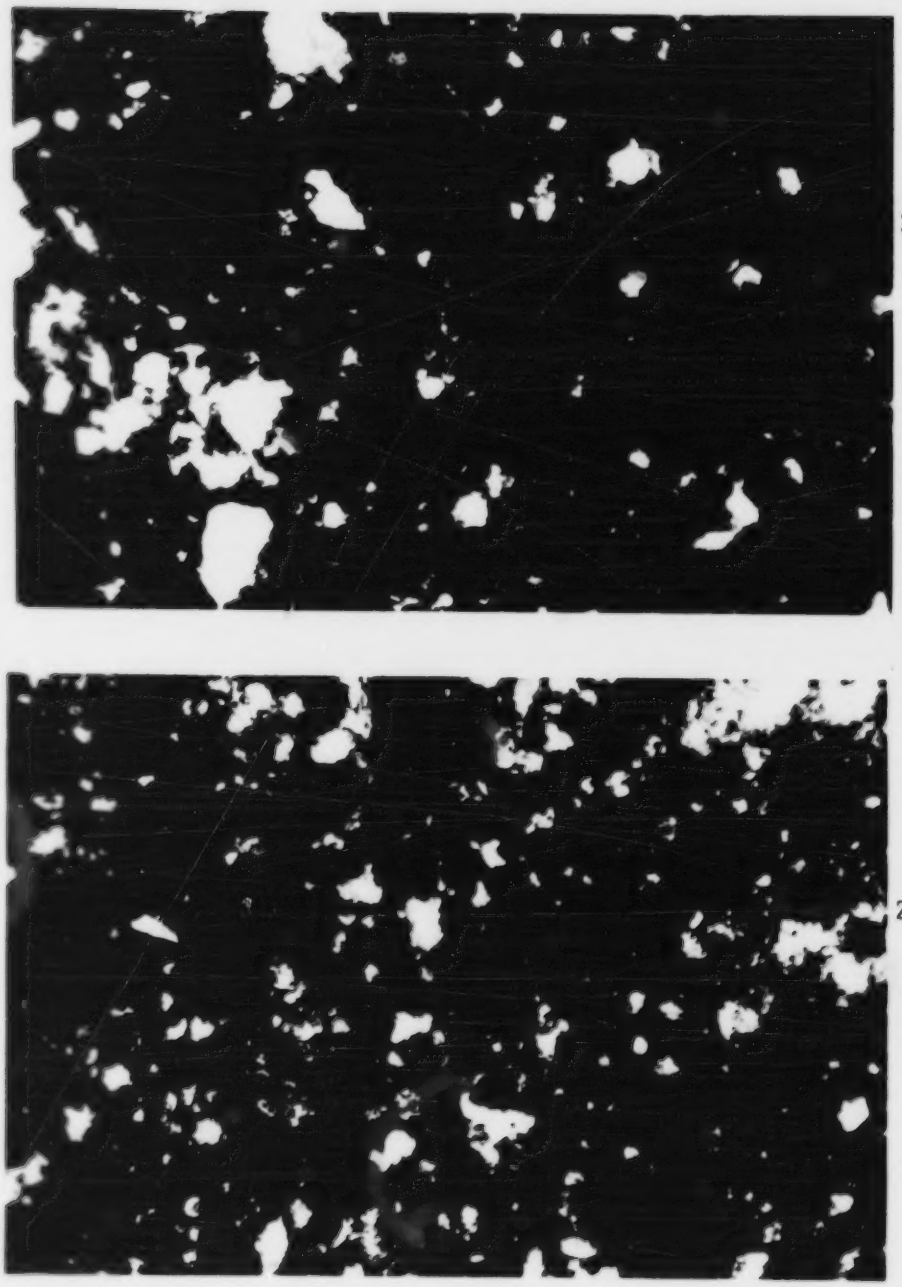


Figure 5. Thin Section of Oil Shale Zone B and Zone C Parallel to the Bedding Plane. Magnification 100X.

Distinctive kerogen bodies of about 150 microns are encountered in sample zones A and C and about 300 microns in sample zone B, but the distribution is less than 1% to 2% at a magnification of 100X. Representative thin section photographs of the oil shale are presented in Figures 4 and 5.

5.3 Processing and Upgrading of Zone C Oil Shale

5.3.1 Rational for Selecting Zone C Oil Shale

Zone C oil shale was selected for processing and upgrading testing because it appeared to be the thickest of the four exposed zones, (A,B,C,E), sampled from the Pictou oil shale deposit, even though it has an oil yield of 5.0 gal/ton, Table 6. The shale oil recovered by Fischer Laboratory retort from sample zone C has a high percentage of small chain hydrocarbons (Appendix 1), as well as a calorific value and a density next to the oil extracted from the sample zone B, Table 7.

5.3.2 Preparation of Samples For Testing

The oil shale sample which had been crushed to 4.75mm was ground and screened by five size fractions to produce samples for heavy liquid separation, Wilfley table separation and flotation tests.

Table 10. Grinding Tests Particle Size Distribution, Zone C.

Particle Size	Feed Sample		Dry Grinding Rod Mill		Dry Grinding Ball Mill		Wet Grinding Rod Mill		Wet Grinding Ball Mill	
mm	% wt.	% cum wt.	% wt.	% cum wt.	% wt.	% cum wt.	% wt.	% cum wt.	% wt.	% cum wt.
4.75	5.17	5.17	0.00	0.00	4.50	4.50	3.65	3.65	4.23	4.23
2.36	32.84	38.01	0.03	0.03	30.27	34.77	14.59	18.24	36.36	36.36
0.60	48.36	86.37	4.33	4.36	27.88	62.65	26.38	44.62	27.02	67.62
0.25	12.18	98.55	37.15	41.51	2.91	65.56	11.95	56.54	4.33	71.95
0.15	1.33	99.88	15.56	56.07	1.93	67.49	4.85	61.42	1.17	73.12
0.075	0.12	100.00	14.83	70.90	6.29	73.78	4.55	65.97	0.91	74.03
0.045	0.00	100.00	22.10	94.00	9.25	83.03	3.04	69.01	1.11	75.14
-0.045	0.00	100.00	6.00	100.00	16.97	100.00	30.99	100.00	24.86	100.00

Grinding time 1 hour
Sample weight 9 kg
Charge of rods 9 kg
Charge of balls 3 kg
Wet Grinding 50% wt. solids and 1% sodium silicate

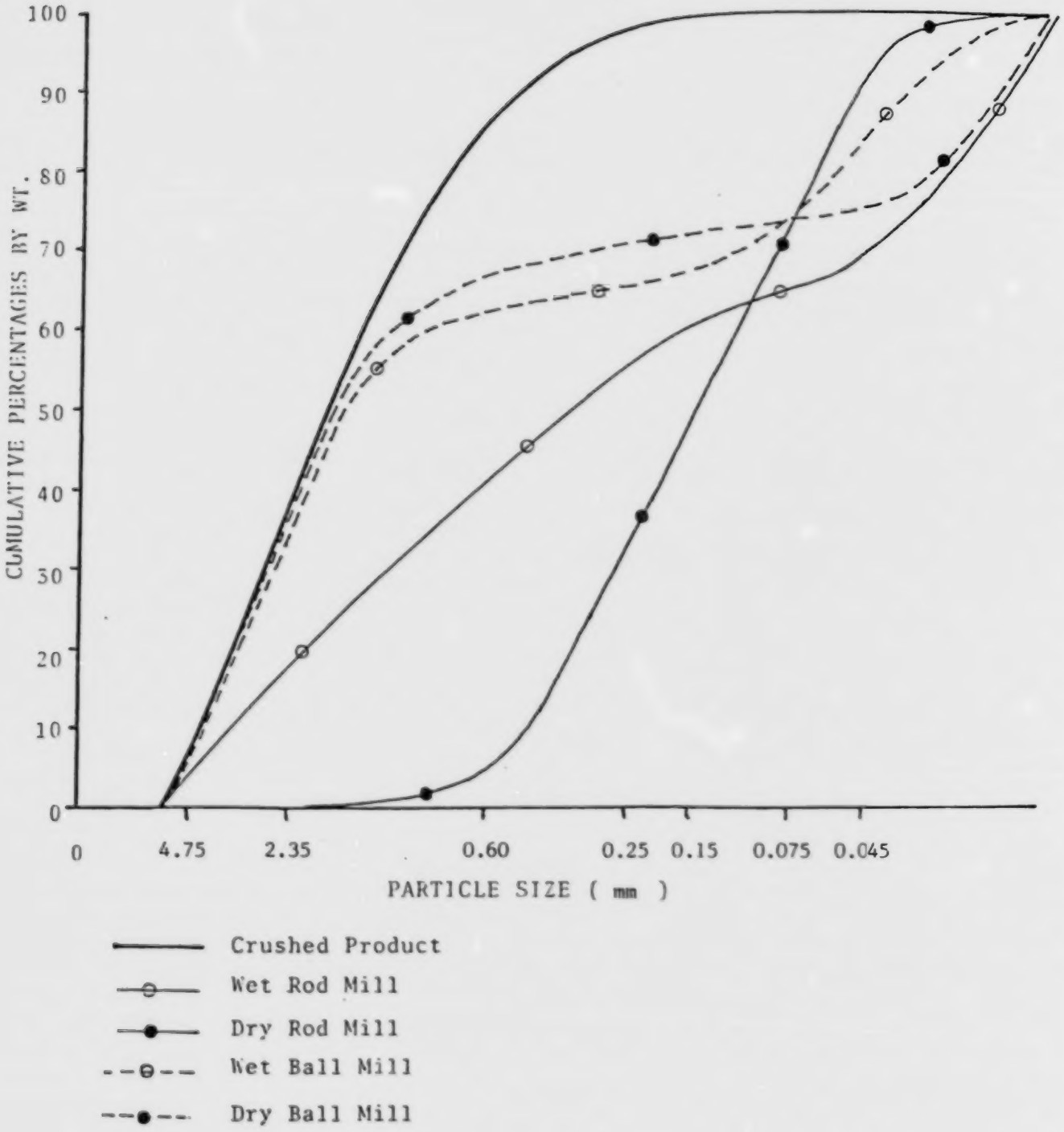


Figure 6. Cumulative Diagram of Oil Shale Zone C Screen Analysis.

Grinding tests were performed under wet and dry conditions with a ball and a rod mill. Table 10 presents the results from 1 hour of grinding in an 8 inch diameter ball mill. Figure 6 shows the cumulative diagram of screen analysis of crushed and ground products.

Dry grinding with a rod mill produced approximately 90% wt. of fractions -600 +74 microns and was chosen to produce the feed sample for the heavy liquid separation and Wilfley Table separation tests.

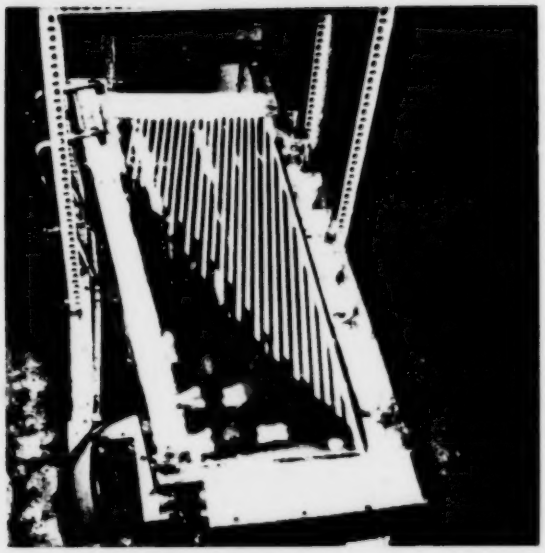
Wet grinding produced larger amounts of finer fractions. The particles of kerogen liberated with a wet rod mill appeared cleaner, with less impcted impurities when viewed under the microscope, than those liberated by wet ball grinding. The 100% passing 45 microns sieve was obtained by increasing the rods charge from 9kg to 14kg and grinding for 1 hour.

5.3.3 Heavy Liquid Separation Tests

Aqueous zinc bromide solutions were used to perform sink-and-float tests on -600 +250 and -250 +150 micron fractions. Dry shale samples of 100g and 250ml heavy liquid of 2.35, 2.40 and 2.45 densities were tested in separatory funnels and agitated periodically until complete separation was observed. The products were filtered, washed several times, dried, weighed, homogenized and analysed for carbon.

5.3.4 Wilfley Table Separation Tests

The oil shale samples sized at 250 +150, -150 +75 and -75 +45 microns were tested on a laboratory Wilfley Table No. 15671. Slurries of 10% to 12% wt. solids were agitated for 20 minutes with 1.0% sodium silicate as a dispersant prior to being passed on the table. The samples were subjected to various table tilt angles, flow rates, stroke lengths and speeds. The separation efficiency was poor and the tests were repeated using a ground glass surface and a surface covered with corduroy and neoprene with various riffle arrangements. Figure 7 shows the Wilfley Table with a modified surface and riffles arrangement. The table with the ground glass surface and several riffles arranged at a 5°angle and 2cm apart produced a better separation. The riffles were made of 1.5mm thick strips of wood tapered towards the concentrate end of the table. For uniform distribution of slurry on the table and improved efficiency, the feed ports were opened betweeen 25° and 35°angles, table speed was maximum, the stroke length was less than 10mm and the table tilt angle was less than 3.5°. Spray wash water was controlled from two valves mounted on the spray pipe line. The separation efficiency was determined from 9 cut off points along the discharge end of the table. The collected products were filtered, dried, weighed, homogenized and analysed for carbon. The center discharge points on the table yielded the highest carbon grade (concentrate).



Wilfley Laboratory Table No. 15671 with modified surface and riffles arrangement.

Wemco Fagergren Laboratory Flotation Cell No. 5365 used in oil agglomeration/ brine flotation tests.

Figure 7. Wilfley Laboratory Table and Wemco Fagergren Flotation Cell used in Tests.

5.3.5 Conventional Froth Flotation Tests

Flotation tests were conduucted in a Denver laboratory flotation machine with a 1.5l cell at 10% wt. solids using tap water. The pH of the slurry was measured with a Cole-Parmer pH meter. Sodium hydroxide was used as a regulator to maintain the slurry pH at 8. Three types of frother were evaluated: methyl isobutyl carbinol (MICB), Cresylic Acid and Dow-250-C. Sodium silicate 0.4% was used as a dispersant and 0.075% kerosene as a promoter. Conditioning time was 20 minutes at 1200 rpm, followed by 5 minutes flotation at an impeller speed of 900 rpm and air flow by natural induction. The concentrates and tailings were filtered, dried, homogenized and analysed for carbon content.

5.3.6 Oil Agglomeration/Brine Flotation Tests

Oil agglomeration/brine flotation combines two processes of separation. First, the agglomeration of small hydrophobic kerogen particles in a pre-emulsified oil solution. Secondly, the recovery of the agglomerates by flotation techniques.

The emulsified oil solution was prepared in a 500ml Waring blender. A weighed amount of hydrocarbon oil was added to 500ml of tap water and blended at 18,000 rpm. A stable emulsion was formed after approximately 80 seconds.

Separately in a Wemco Fagergren laboratory flotation cell No. 5353, a 1000ml slurry of brine and oil shale ground to pasing 45 microns sieve was prepared. The emulsified oil in water was transferred from the blender to the cell and mixed with the slurry for 20 minutes at 1200 rpm. During the mixing, the hydrophobic particles coalesed with the oil droplets and formed fine agglomerates. In the flotation stage the cell operated at 1000 rpm and with the air valve fully open. Unless otherwise mentioned, the flotation tests were perfomed at room temperature with a 10% wt. solids and a neutral pH.

The flotation tests were completed with the following variables:

-- Concentration of brine solution (1%, 2% and 3% NaCl).
-- Type of hydrocarbon collector (kerosene, turpentine, paint thinner and methyl hydrate).
-- Amount of collector (0.5%, 1%, 5% and 10%).
-- Flotation time (5, 10 and 15 minutes).

Evaporation tests of the hydrocarbon collectors were conducted at 100°C with 5g dry oil shale mixed with 5ml of collector. Kerosene and paint thinner evaporated after 8 hours, turpentine after 66 hours and methyl hydrate after 2 hours.

Concertrates and tailings produced from the flotation were filtered, washed several times, dried, weighed, homogenized and analysed for carbon.

The rougher concentrate which yielded the highest recovery was passed to a multi-stage cleaning flotation. The concentrate and tailings produced from each stage were filtered, washed, dried, weighed, homogenized and analysed for carbon. Approximately 1kg of final clean concentrate and tailings from the multi-stage cleaning test were produced. Approximately 500g of each were sent to the Research and Productivity Council, Fredericton, N.B. for a complete analysis. The remainder are stored under vacuum.

6. RESULTS AND DISCUSSIONS

6.1 Heavy Liquid Separation

Table 11 shows the test results of two mesh fractions separated at densities of 2.35, 2.40 and 2.45. Figure 8 illustrates the effect of liquid density on carbon grade and recovery for the two fractions. At a liquid density of 2.35, both fractions, -600 +250 and -250 +150 microns, produced similar results. The average concentrate grade was 15.2% carbon, upgraded approximately by a factor of 2, and a 29% recovery.

As the liquid density increased to above 2.40, the separation behaviour between the two size fractions became more distinctive. At a liquid density of 2.45, only the fraction -250 +150 microns responded to separation. The float contained 8.8% carbon at 82.6% recovery. The float could be reground

Table 11. Heavy Liquid Separation Tests.

Liquid Density	Micron Fraction	Float %C	Recovery %C
2.35	-600 +250	15.05	28.85
	-250 +150	15.24	29.32
2.40	-600 +250	10.55	51.75
	-250 +150	11.28	59.71
2.45	-600 +250	7.42	69.52
	-250 +150	8.80	82.65

Figure 12. Wilfley Table Separation Tests. *

Micron Fraction	concentrate %	Recovery %	Tilt Angle deg.	Stroke Length mm.	Flow Rate cc/min.
-250 +150	8.61	37.2	3.5	10.0	300
-150 +75	9.56	50.9	2.0	10.0	200
-75 +45	8.12	70.3	1.5	7.5	200

* Ground glass surface and 5° angle riffles arrangement.
Slurry 11% wt. Solids.

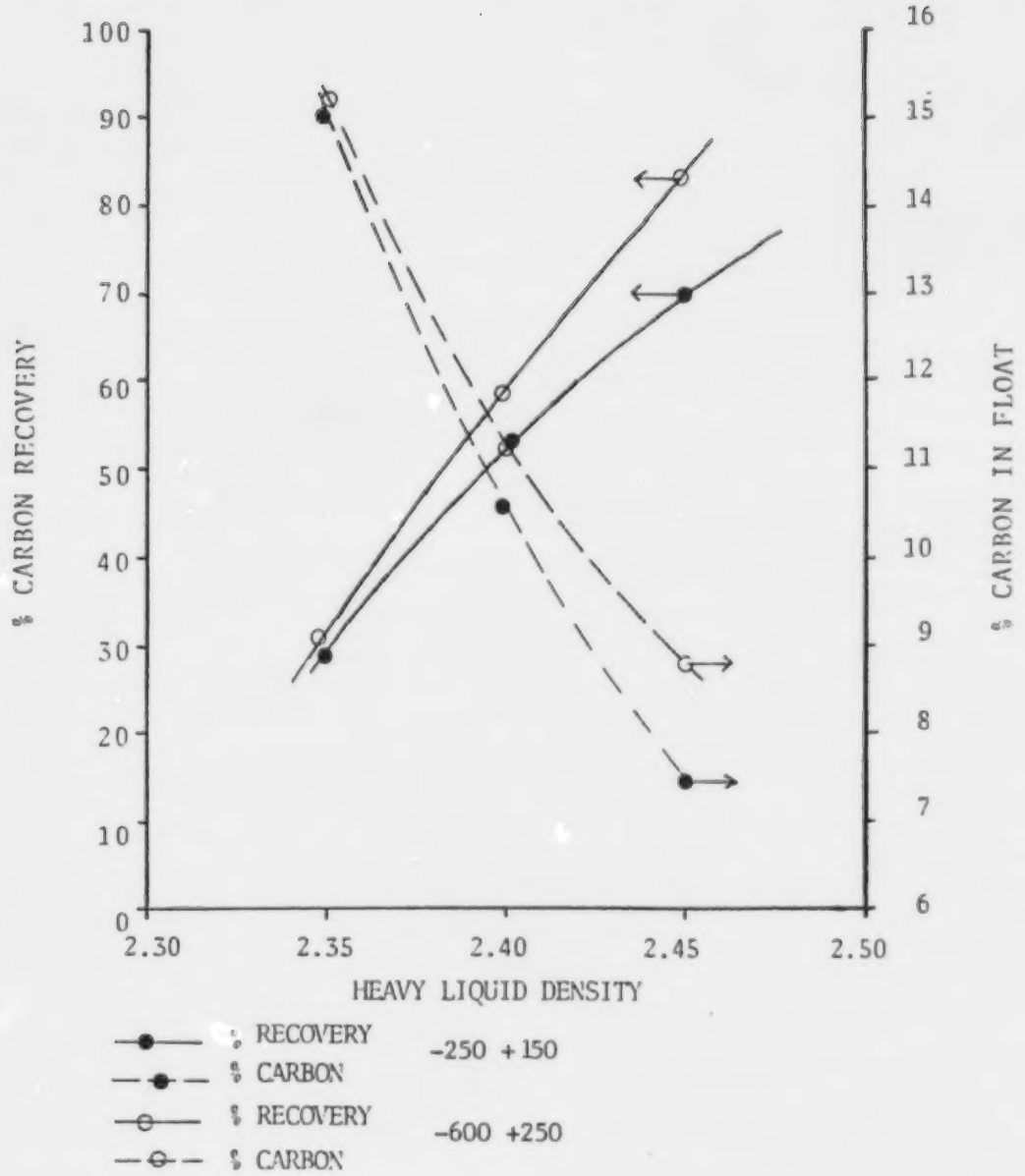


Figure 8. Effect of Liquid Density on Carbon Recovery and Grade for Fractions -600 +250 and -200 +150 Microns

for further treatement and the sink product, representing 33.3% wt. and a calculated 3.8% carbon, could be rejected.

The heavy liquid separation tests proved that coarser size fractions of shale sample zone C could respond to a preliminary separation. This indicates that variations in shale quality from a mine can be moderated by an initial heavy liquid separation stage. Furthermore, such separation would reduce the amount of shale to be reground for further treatement by flotation.

6.2 Wilfley Table Separation

Table 12 shows the results produced by three sized oil shale fractions from a single pass on the Wilfley Table with ground glass surface and a 5°angle riffles arrangement. Figure 9 graphs the effect of particle size on carbon grade and recovery under the conditions listed in Table 12 and Section 5.3.4.

The fraction -150 +75 microns produced the higher grade, whereas the fraction -75 +45 microns produced the higher recovery and the lowest grade. Separation efficiency by tabling is affected by many variables. The small differences in specific gravity between the shale components and the limited mesh size range responding to the table will limit the application of the tabling process on oil shale to zone C.

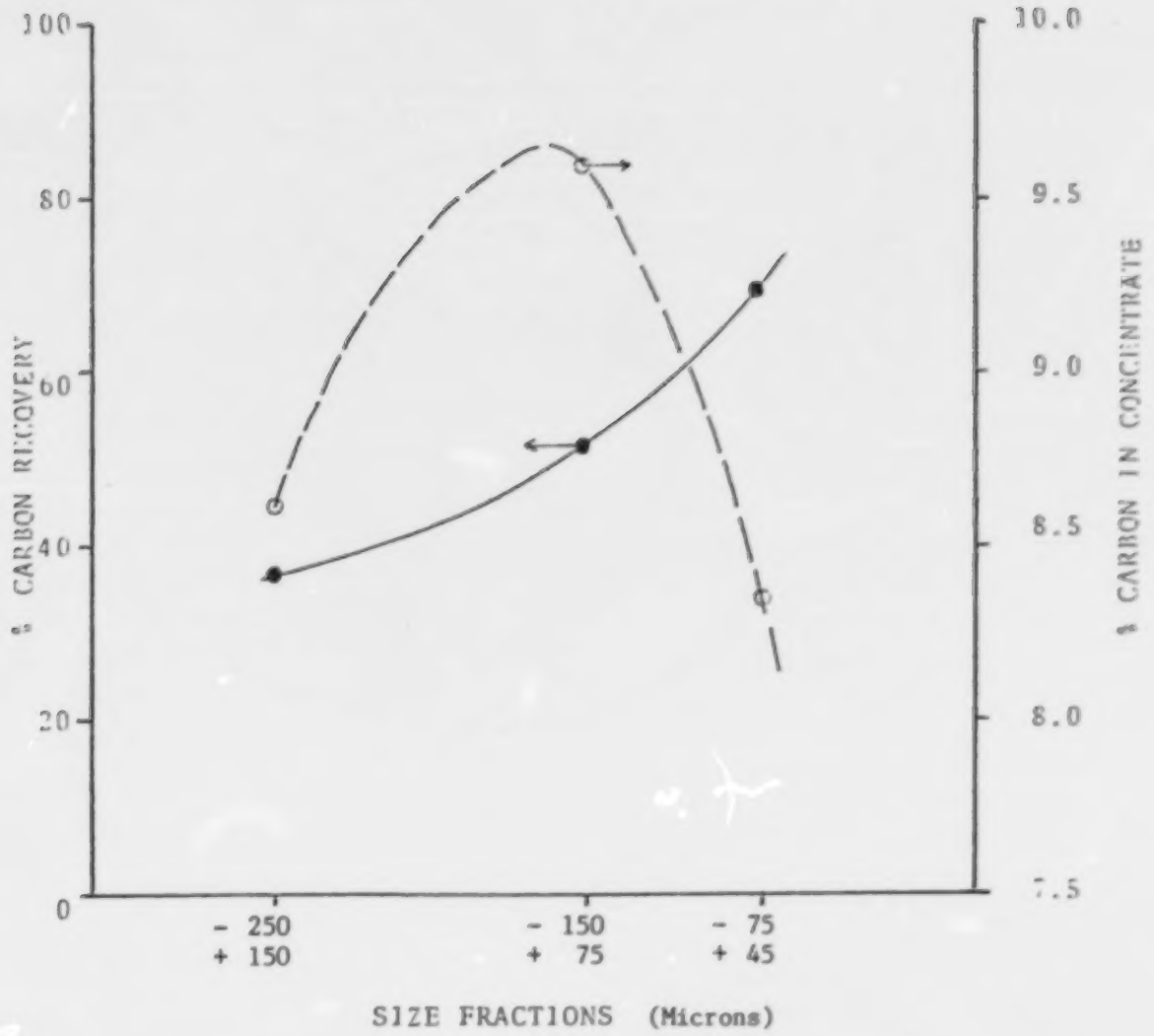


Figure 9. Effect of Particle Size on Carbon Recovery and Grade (Wilfley Table Separation).

6.3 Conventional Flotation

The flotation results of -74 +44 microns are presented in Table 13. Test # 1 and #2 were modeled after Misra, M. et al. (14). The flotation selectivity response to the three types of frother was poor. Test # 1 with MICB frother was repeated on the fraction -45 microns at 5, 10 and 15 minutes flotation time. The test results are presented in Table 14. The increase in flotation time and a finer size fraction did not significantly influence the quality of separation. As a result, no attempts were made to further optimize the conditions. Instead, emphasis was placed on other methods of separation, suitable for fine particle size.

6.4 Oil Agglomeration/Brine Flotation

Oil agglomeration has been used with varying degrees of success in the recovery of coal fines from washing plant rejects. The addition of oil to a suspension of coal sets up a flocculation process in which oil droplets form pendular bridges between the coal particles. Flocs, macroflocs or spherical agglomerates could be formed. Their size and strength are influenced by the quantity and type of collector oil used as well as by the hydrodynamic conditions prevalent during the agglomeration process. Function of their physical characteristics, the agglomerates are recovered by various screening devices or by froth flotation (28).

Table 13. Frother Comparison Tests - Conventional Flotation.

	Concentrate % Carbon	Tailings % Carbon	% Recovery
Test #1 MICB 0.075%	11.66	6.39	24
Test #2 Cresylic Acid 0.075%	9.38	5.74	40
Test #3 Dow-250-C 0.075%	12.66	6.07	33

Conditioning time 20 min.
Flotation time 5 min.
Slurry 10%wt. solids
Slurry pH 8
Promotor kerosene 0.075%
Dispersant Na_2SiO_3 0.4%wt.
pH regulator NaOH
Room temperature

Table 14. Effect of Flotation Time - Conventional Flotation.

Flotation time (min.)	%C Concentrate	% Recovery
5	15.20	22
10	10.90	42
15	8.79	63

Oil agglomeration attempts of oil shale from Lewis County, Kentucky, were reported by Datta, R.S. and C.A. Salotti (9), the agglomeration process responded less satisfactorily.

The use of brine solution in this study was intended to aim at reducing the hydrolysis of clay particles and their transition into a colloidal state. It was observed during testing that the presence of colloidal clays rendered a deliterious effect on flotation selectiveness of kerogen in the concentrate grade. The changes in the chemistry of clay minerals under different enviornmental conditions has received little attention to date and is beyond the scope of this study.

Table 15 presents the results of oil agglomeration/brine flotation behaviour of shale zone C as a function of hydrocarbon collector type, concentration of brine solution, amount of collector and flotation time. The percentage recovery reported in Table 15 was calculated using the formula:

$$R = 100c\ (f - t)/f(c - t)$$

Where: f = Carbon assays of feed

c = Carbon assay of concentrate

t = Carbon assay of tailing

and the value was rounded to the nearest unit (29). The Carbon assasys were performed by the Atlantic Industrial Research Institute, N.S., using a Leco induction furnace model # 521-000. The feed samples contained 7.2% Carbon.

Table 15. Oil Agglomeration/Brine Flotation Tests.

Test #	Float min.	Collector	NaCl %	Product	Carbon %	Recovery %
1	5	5% Kerosene	3	Conc Tails	12.40 5.00	51
2	5	5% Turpentine	3	Conc Tails	9.30 4.67	70
3	5	5% Paint Thinner	3	Conc Tails	9.20 5.09	65
4	5	5% Methyl Hydrate	3	Conc Tails	13.70 5.02	48
5	5	5% Kerosene	1	Conc Tails	11.10 6.12	36
6	5	5% Kerosene	0	Conc Tails	9.66 7.13	3
7	5	10% Kerosene	3	Conc Tails	10.20 6.69	20
8	5	0.5% Kerosene	3	Conc Tails	11.90 5.03	52
9	5	1% Kerosene	3	Conc Tails	10.80 4.21	68
10	5	1% Kerosene	2	Conc Tails	11.60 4.42	62
11	10	5% Kerosene	3	Conc Tails	9.30 3.79	80
12	15	5% Kerosene	3	Conc Tails	8.05 2.86	93
13	15	1% Kerosene	3	Conc Tails	8.13 2.90	93
14	5	5% Kerosene	3	Conc Tails	10.30 4.85	61 *

* Slurry Temperature 40° C

The evaporation duration of kerosene, turpenine, methyl hydrate and paint thinner were evaluated. Kerosene and paint thinner evaporated after 8 hours at 100°C, turpentine after 66 hours and methyl hydrate after 2 hours. Kerosene produced the second highest grade concentrate after methyl hydrate, and was selected as a collector for further testing. Kerosene has a longer evaporation time which allows it to be recovered,it is also the least expensive.

The effect of brine concetrations with 0%, 1% and 3% NaCl on flotation selectiveness is revealed by Tests #6, #5 and #1, and graphed as a function of carbon grade and recovery in Figure 10. Maximum carbon grade and recovery were obtained with brine concentrations ranging from 2.5% to 3.0% NaCl. Above this range, the effect on selectiveness levels off. At concentrations below 2.0% NaCl the selectiveness decreased, probably because there was not sufficient NaCl in solution to satisfy the cationic charges of some of the hydrolysed clays.

Contrary to the agglomertion of coal (28), lower ash content and higher recovery with increased dosage of collector, the recovery of shale's organic matter under the same conditions was found to reach a maximum at approximately 1-2% kerosene. The quality of concentrate behaved even more differently, it reached a maximum at 6-7% kerosene and a minimum at 2-3% kerosene consumption , Figure 11 and Tests # 1,7,8 and 9 in Table 15.

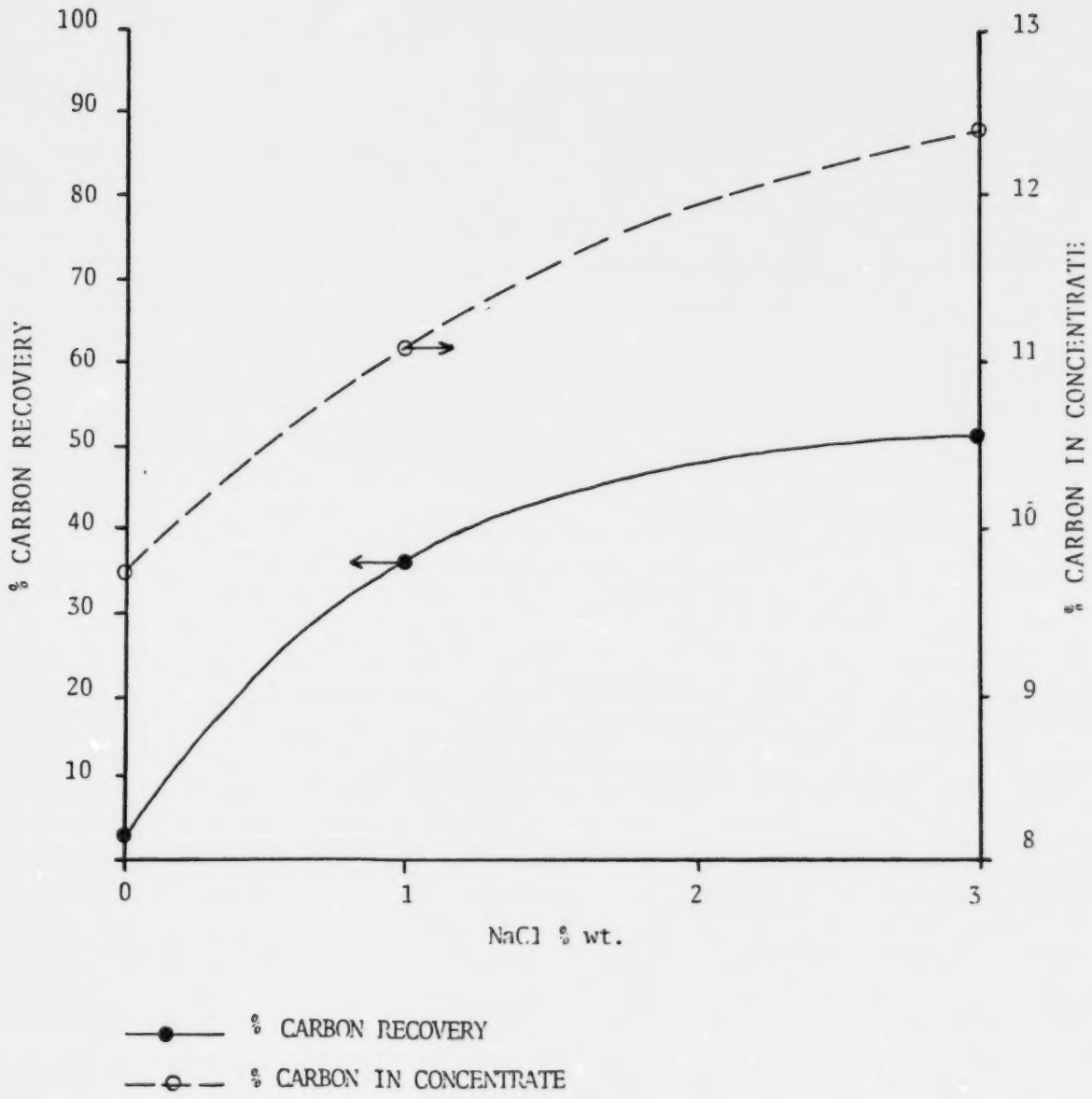


Figure 10. Effect of Brine Concentration on Carbon Recovery and Grade in Oil Agglomeration/Brine Flotation.

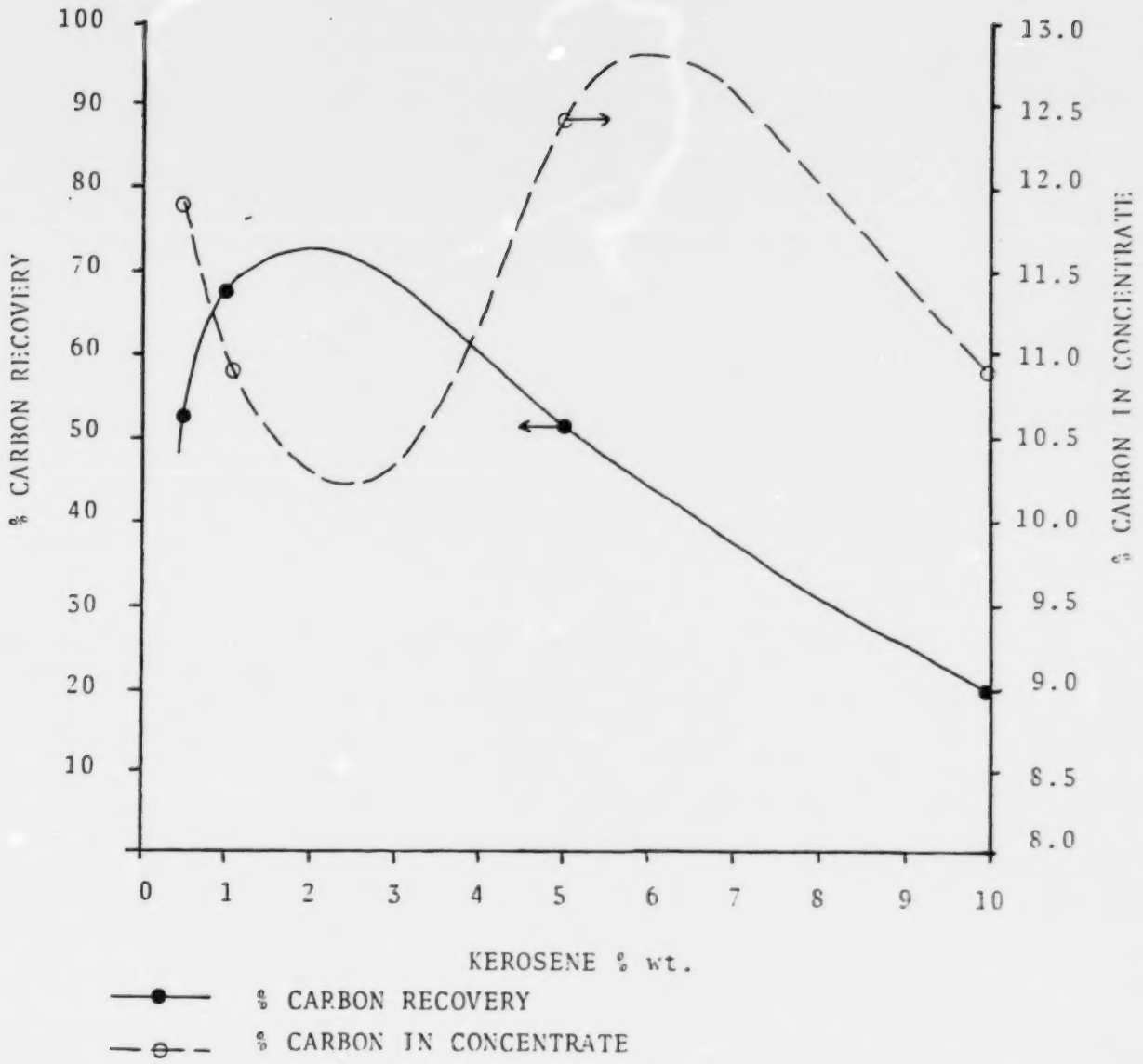


Figure 11. Effect of Amount of Kerosene on Carbon Recovery and Grade in Oil Agglomeration/Brine Flotation.

The maximum increase in the recovery was found to be associated with a reduction in the quality of the concentrate which is most probably due to the increased clay content entrainment within the agglomerated organic particles. A decrease in the amount of kerosene produced an increase in the froth. At approximately 1% addition of kerosene and 5 min. flotation time, the grade of concentrate and recovery reached the highest values. Beyond this point, the values were sharply different until they reached a second common point but of lower values. No frother was added to the previously discussed experiments, since it was found that the use of conventional reagents (MIBC, Cresylic acid, Pine oil, etc.) is detrimental when used under the oil agglomeration/brine flotation conditions investigated. The presence of small quantities of frothers was observed to reduce the kerosene/brine solution interfacial tension and weakened the oil bridges holding the agglomerated organic matter together.

The different flotation times with samples containing 5% and 1% emulsified kerosene is given by Tests #1,9,11,12 and 13 in Table 15. The effect of flotation time on the concentrate grade and recovery of these two samples, Figure 12, is compared with that from the conventional flotation tests.

At 5 min. flotation time, the conventional flotation produced higher grade concentrate and the lower recovery than oil agglomeration/brine flotation. At 15 min. flotation time,

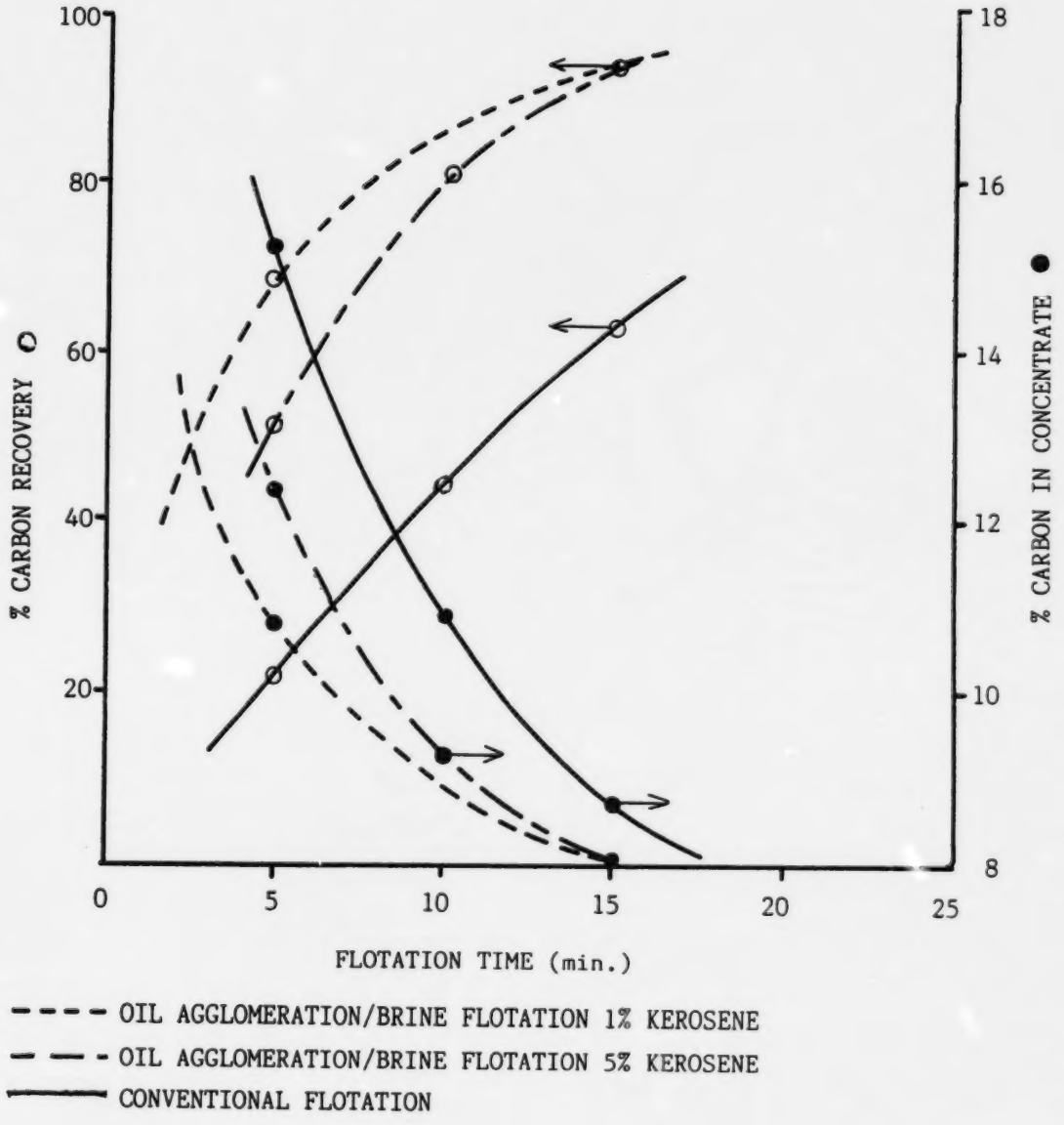


Figure 12. Flotation Time Versus Carbon Grade and Recovery for Conventional Flotation and Oil Agglomeration/Brine Flotation.

the carbon recovery by oil agglomeration/brine flotation is approximately 50% higher than by conventional flotation, while the differences in the concentrate grade for the two methods decreased to less than 9%. A maximum of 93% carbon recovery was achieved by oil agglomeration/brine flotation with 1% and 5% emulsified kerosene after 15 minutes flotation time.

Considering the optimal conditions developed thus far, a multi-stage cleaning of the concentrate with the highest perecntage recovery was tested. Figure 13 presents the development of a flow sheet and the pertaining results obtained after several test runs. In this regard, the rougher concentrate from the oil agglomeration flotation using 1% kerosene and 3% NaCl was cleaned three times decreasing the flotation time and concentration of brine solution as follows:

Stage	Flotation time	Brine concentration
Rougher	15 min.	3% NaCl
Cleaner #1	10 min.	2% NaCl
Cleaner #2	8 min.	2% NaCl
Cleaner #3	5 min.	2% NaCl

Microscopic views of the oil agglomeration/brine flotation feed sample and cleaner #1 concentrate are shown in Figure 14. The final concentrate or cleaner #3, in Figure 15. The effect of multi-stage cleaning on the carbon grade and recovery is graphed in Figure 16.

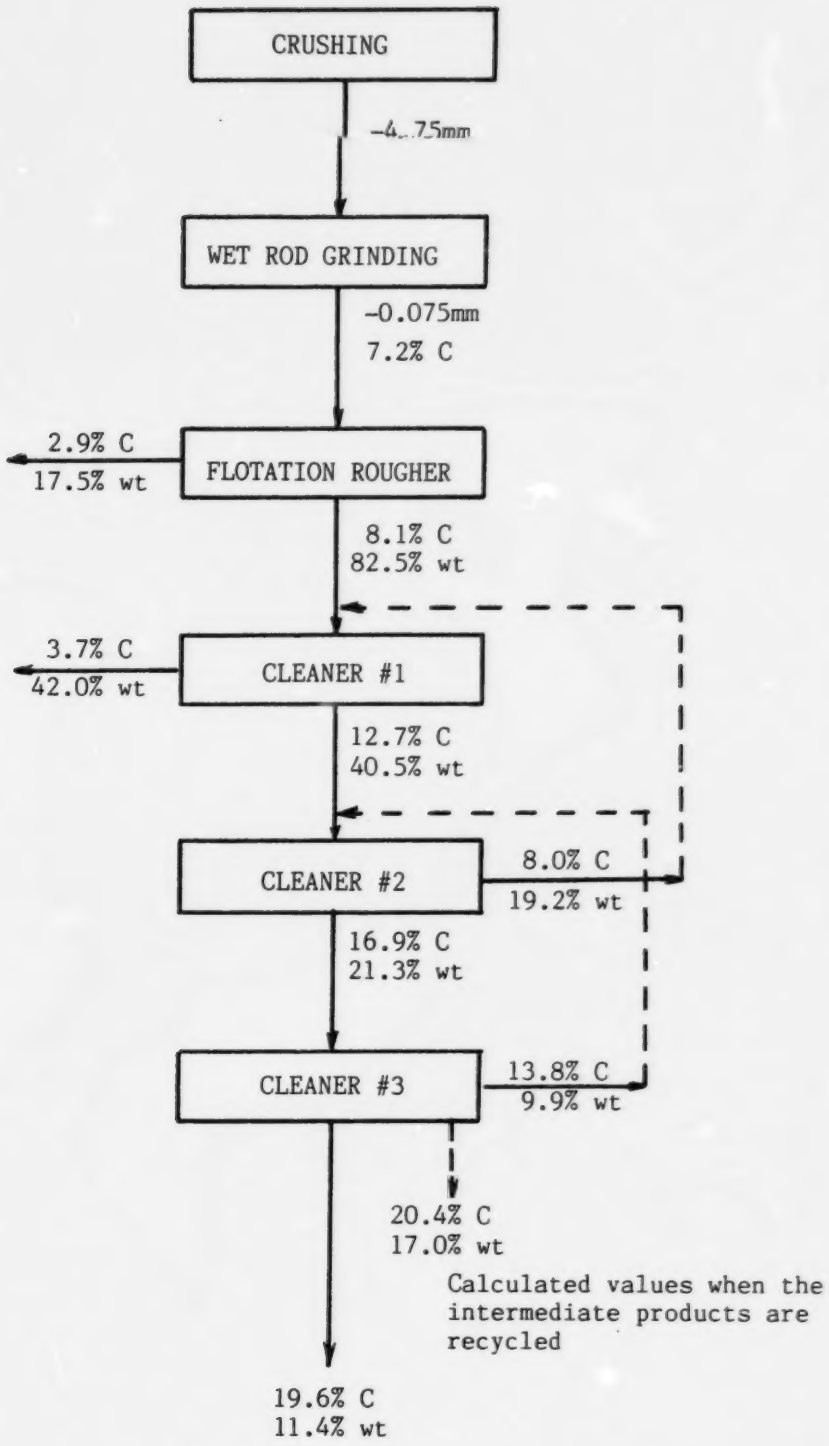
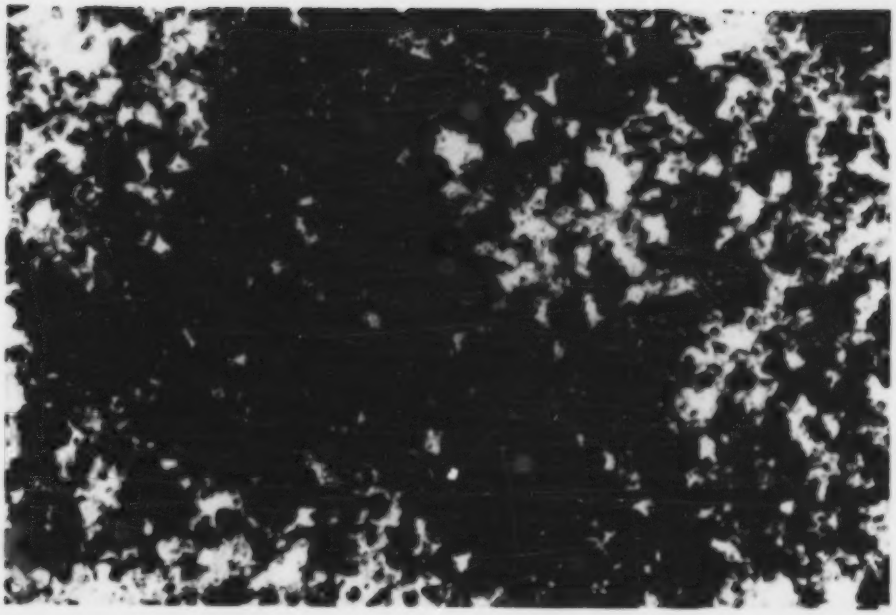
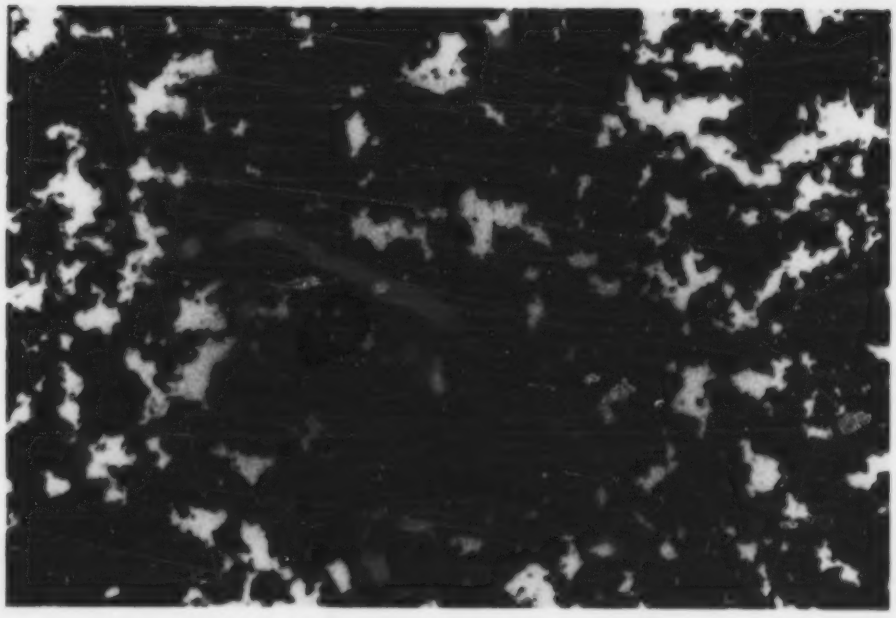


Figure 13. Simplified Flowsheet for Oil Shale Upgrading by Oil Agglomeration/Brine Flotation.



Feed Sample



Cleaner #1 Concentrate.

Figure 14. Oil Agglomeration/Brine Flotation Feed and Cleaner #1 Concentrate, Magnification 100X

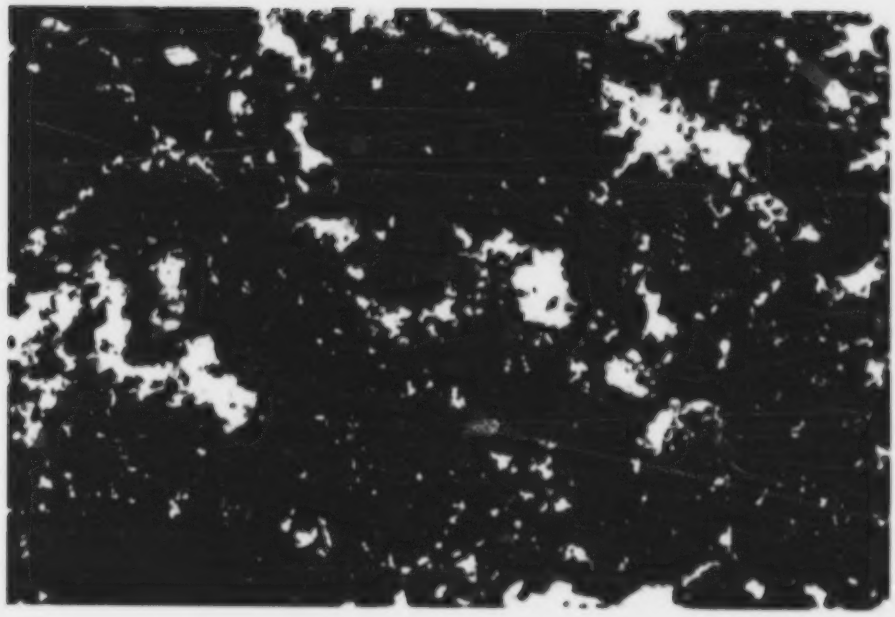


Figure 15. Oil Agglomeration/Brine Flotation Final Concentrate, Magnification 200X.

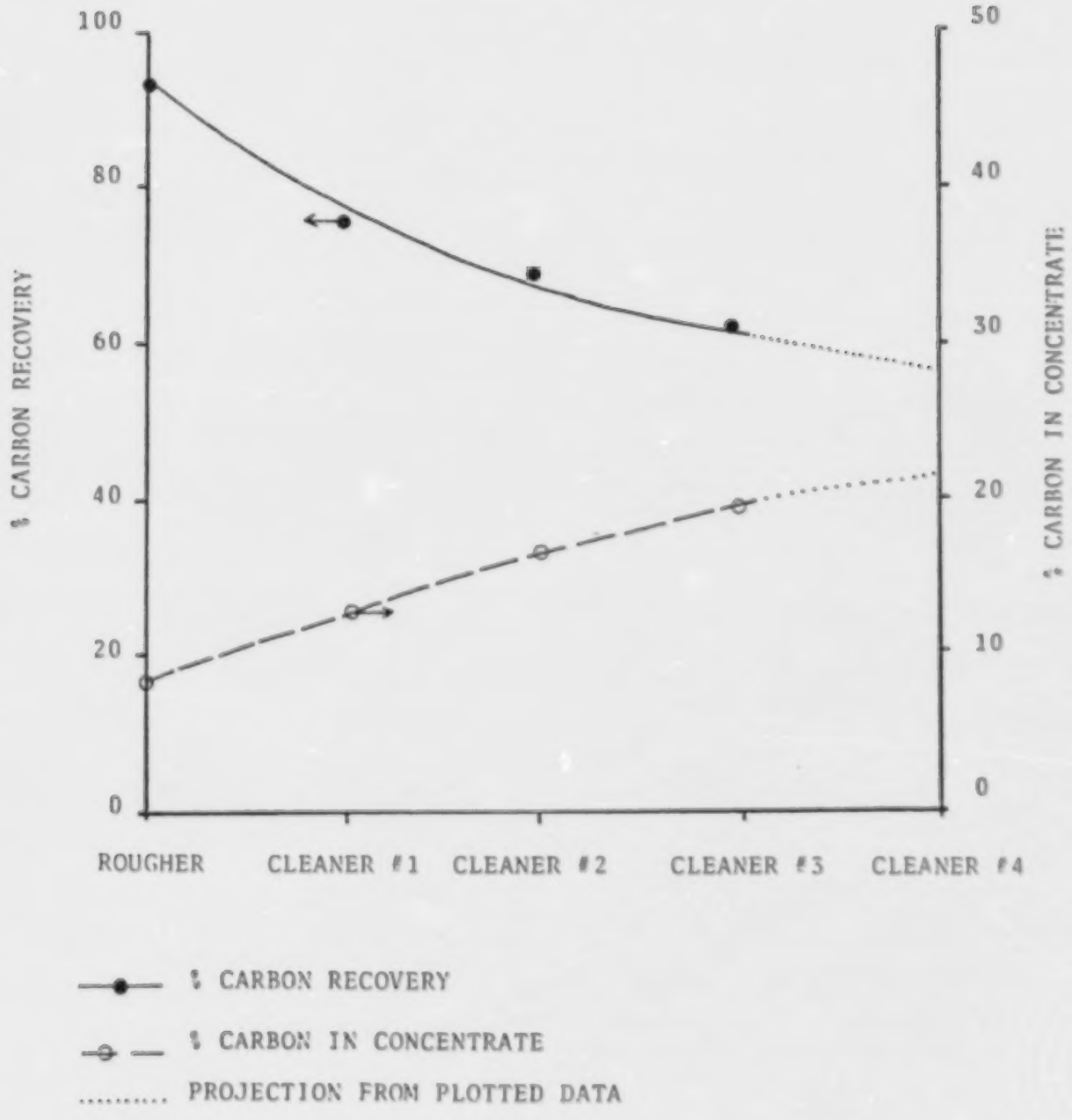


Figure 16. Effect of Multi-Stage Cleaning of Rougher Concentrate.

An additional cleaning stage, as projected from the plotted data, in Figure 16, will reduce the percentage recovery from 62% to approximately 58%, while the concentrate grade increased to approximately 21% carbon. To enhance further the efficiency of cleaner #3, would require finer grinding to possibly liberate the very impure phase of kerogen, intimately associated with the colloidal clay phase, Section 5.2.2. In a closed circuit with recycling of the tailings from cleaner #2 and #3, the grade of concentrate is expected to be above 20% Carbon, and the weight rate increased from 11.4% to 17%, calculated values presented in Figure 13.

6.5 Characteristics of Upgraded Oil Shale Zone C

Approximately 500g of final concentrate and tailing produced from oil agglomeration/brine flotation of oil shale zone C, Figure 13, were analysed by the Research and Productivity Council, N.B., Report No. AS/85/111. The results are summarized in Tables 16 to 20 and compared with oil shale zone C prior to treatment. A hydrocarbon profile of upgraded oil shale is presented in Appendix A3. The analysed oil was recovered at RPC using a Fischer laboratory retort. The relationship between organic carbon and oil yield (Fischer Assay) of the four sampled oil shale zones and the upgraded sample zone C oil shale is illustrated in Figure 17. The linear slope was calculated using the analytical data from Tables 6 and 7.

Table 16. Proximate and Ultimate Analysis of Upgraded Oil Shale Zone C (wt.%).

Proximate Analysis

Sample	Moisture	Ash	Volatile Matter	Fixed Carbon*
Concentrate	0.34	72.00	18.1	9.56
Tailing	0.46	90.64	8.4	0.5
Raw Oil Shale	0.74	86.17	9.7	3.4

* "Fixed Carbon" is a calculated value which results from the summation of percentage of moisture, ash and volatile matter subtracted from 100.

Ultimate Analysis

Sample	Organic Carbon	Mineral Carbon	H	N	S	Calorific Value (BTU/lb)
Concentrate	16.9	2.2	2.18	0.66	0.87	3240
Tailing	2.8	0.4	0.77	0.35	0.31	253
Raw Oil Shale	6.99	0.5	1.45	0.50	0.48	1021

Table 17. Ash Analysis (Major Oxides) of Upgraded Oil Shale Zone C (wt.%).

	Concentrate	Tailing
SiO_2	64.8 (46.7)	62.8 (56.9)
Al_2O_3	14.86 (10.70)	15.96 (14.47)
Fe_2O_3	10.41 (7.50)	12.21 (11.07)
CaO	1.09 (0.78)	1.86 (1.69)
MgO	0.97 (0.70)	0.72 (0.65)
K_2O	2.30 (1.66)	2.31 (2.09)
Na_2O	1.67 (1.20)	1.18 (1.07)
TiO_2	0.70 (0.50)	1.14 (1.03)
P_2O_5	0.16 (0.12)	0.66 (0.60)
Ignition Loss	1.28 (0.92)	0.76 (0.69)

The ash analysis was performed using the ash resulting from ignition of the shale to 750 C. Values in brackets represent the composition on an "as-received" basis.

Table 18. Fischer Assay of Upgraded Oil Shale Zone C.

	Concentrate	Tailing
Wt. shale samples (g)	100	100
Total loss (g/sample)	11.0	2.5
Wt. oil recovery (g)	5.99	0.27
Density oil (g/ml @ 15.5 C)	0.8784	0.8784*
Oil yield (%)	6.0	0.3
Water yield (%)	2.1	1.3
Gas lost (%)	2.9	0.9
Oil yield (Imp.gal/ton)	13.6	0.6
(gal/ton)	16.4	0.7

* Assumed value due to insufficient oil recovered.

Table 19. Analysis of Oil Recovered from Upgraded Oil Shale Zone C (wt.%).

Sample	C	H	N	S	Calorific Value (BTU/lb)
Concentrate	86.8	11.84	0.60	0.36	18,764
Tailing	86.5	11.61	0.85	0 40	--

Table 20. Proximate Analysis of Spent Shale (Concentrate and Tailing) (wt.%).

Sample	Moisture	Ash	Volatile Matter	Fixed Carbon
Concentrate	<0.1	82.20	6.3	11.5
Tailing	0.16	94.84	4.8	0.2

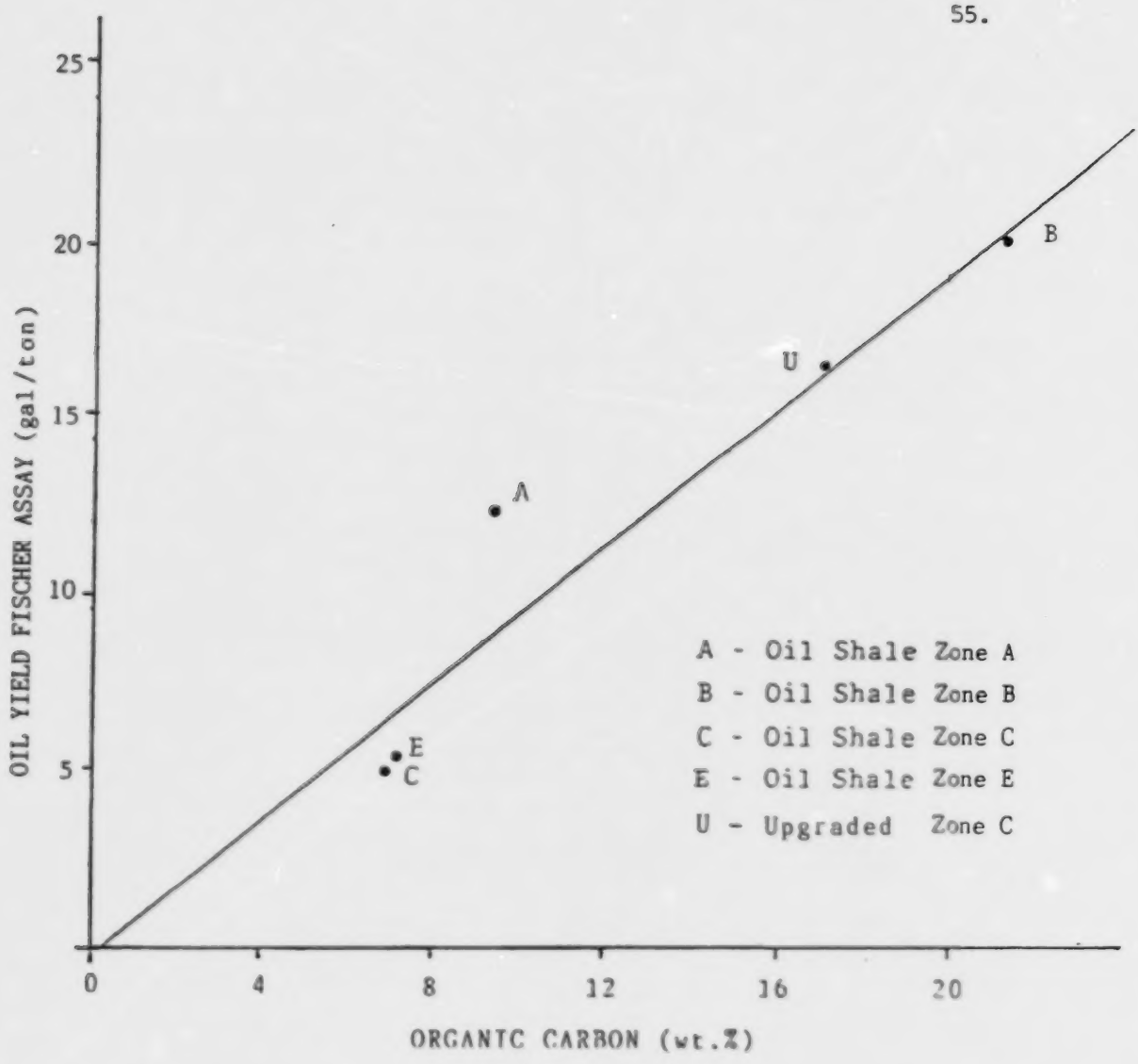


Figure 17. Relationship Between Organic Carbon and Oil Yield of Sampled and Upgraded Zone C Pictou Oil Shale.

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APPENDIX A1

Thermal Analysis of Oil Shale Zones

DUNLOP RESEARCH CENTRE

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Nova Scotia
P.O. Box 1000
Halifax, N.S.
B3J 2X4

SUBJECT Thermal Analysis of Oil Shale Samples

EXPERIMENTAL

TGA and DSC were run on the 9 oil shale samples that were sent to us.

Conditions used for TGA were:

Heating rate: 20°/min from ambient to ca. 950°C
Sample weight: ca. 50 mg
Atmosphere: air at 100 ml/min

Conditions used for DSC were:

Heating rate: 20°/min from ambient to 650°C
Sample weight: ca. 5 mg
Atmosphere: air at 100 ml/min
Closed aluminum pans with perforated lids were used.

...../2

"The information set forth above (the "information") was derived by analytical techniques that Dunlop (Canada) Inc. believes to be reliable. No representations, collateral agreements, conditions, warranties, or guarantees, expressed or implied, statutory or otherwise, with respect to the information or to the rights and liabilities of the purchaser and Dunlop (Canada) Inc., other than those specifically set out herein or attached hereto, have been made by Dunlop (Canada) Inc., its affiliates, officers or agents. Without limiting the generality of the foregoing, every implied condition, warranty or guarantee, statutory or otherwise is excluded. Dunlop Research Centre disclaims all liability for incidental or consequential damages resulting from the use of the information".

RESULTS

TGA: A chart of weight loss vs. temperature and derivative of weight loss vs temperature along with a summary table of the weight loss events for each run is enclosed.

The small weight loss up to 150°C is probably due to moisture.

DSC: The total area under each of the exotherms is shown on each DSC chart in joules/gram.

In general, the various peaks in the DSC correspond quite well with the various weight loss steps observed in the TGA for each sample.

Also the heat of oxidation appears to correlate reasonably well with the total weight loss observed.

If you have any questions about interpretation of any of these results, please don't hesitate to call.

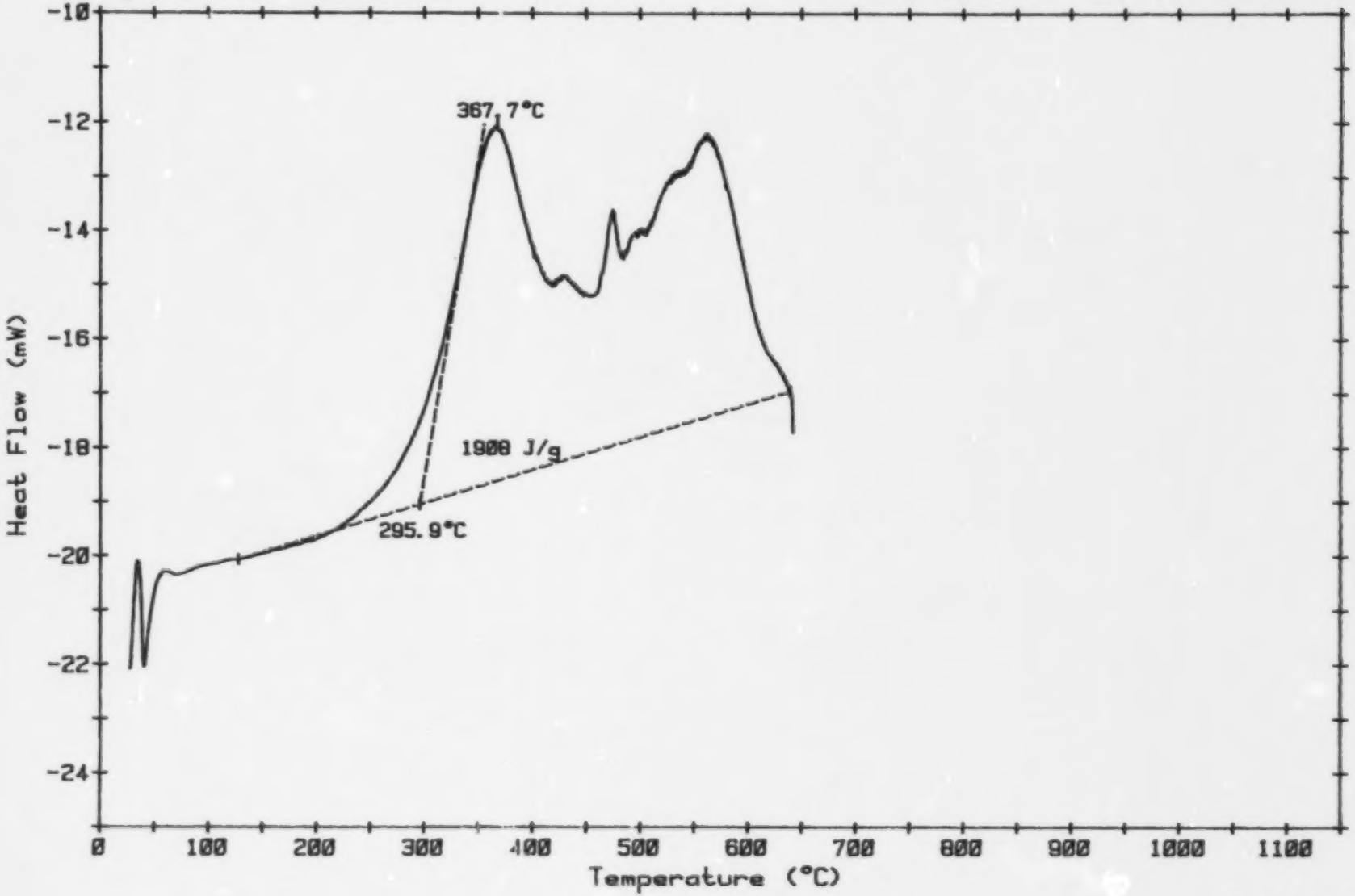
N.V. Schwartz
DUNLOP RESEARCH CENTRE

NVS/lmc
Job #85-36C
February 19, 1985

Sample: A
Size: 6.390 mg
Rate: 20.0DEG/MIN AIR
Program: Interactive DSC V2.0

DSC

Date: 15-Feb-85 Time: 11:15:36
File: A.02 DRC 12
Operator: GN
Plotted: 18-Feb-85 14:05:07

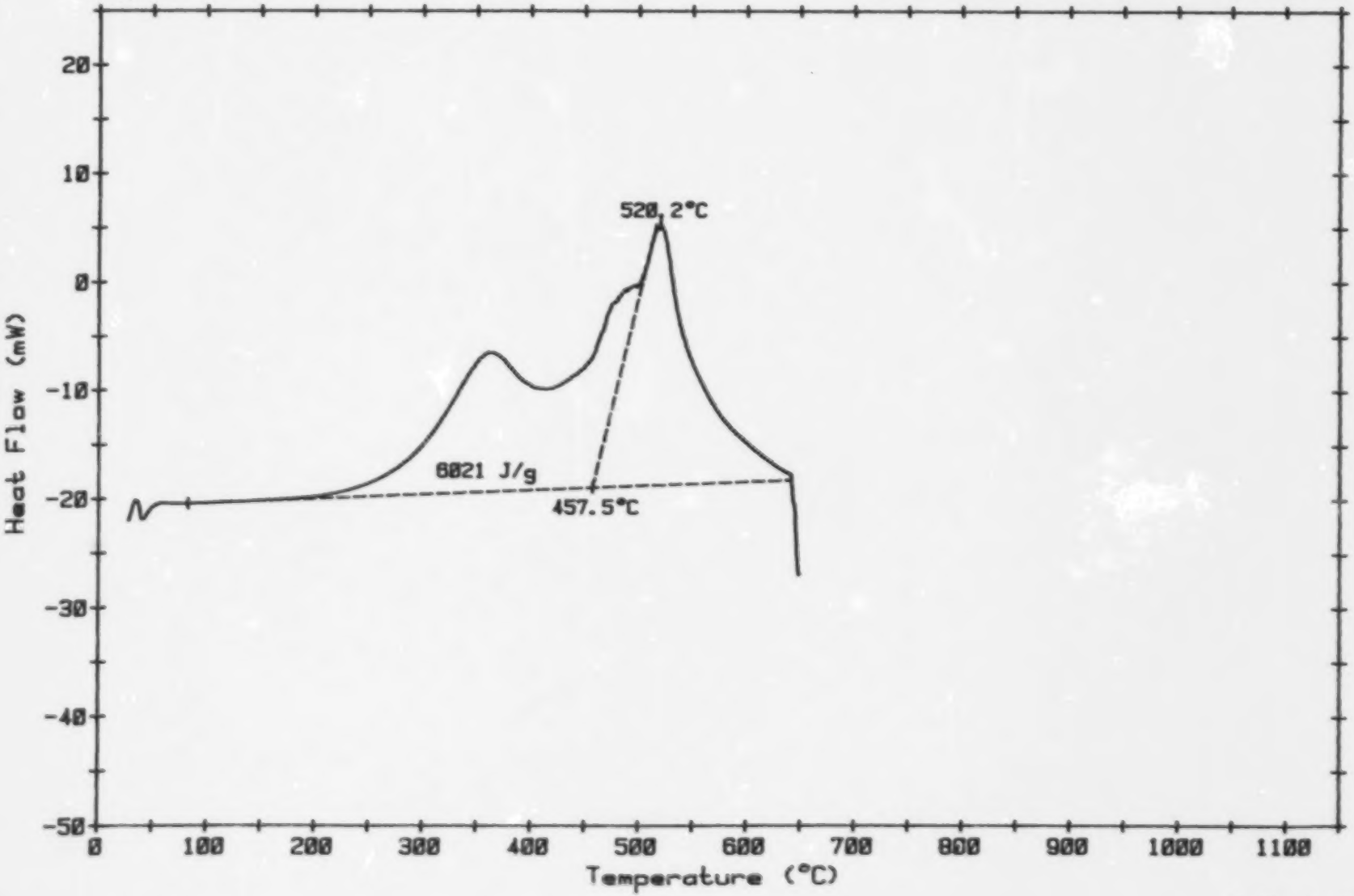


DuPont 1090

Sample: B
Size: 5.78MG
Rate: 20.0DEG/MIN AIR
Program: Interactive DSC V2.0

DSC

Date: 18-Feb-85 Time: 10:55:29
File: B.02 DRC 12
Operator: GN
Plotted: 18-Feb-85 11:53:52

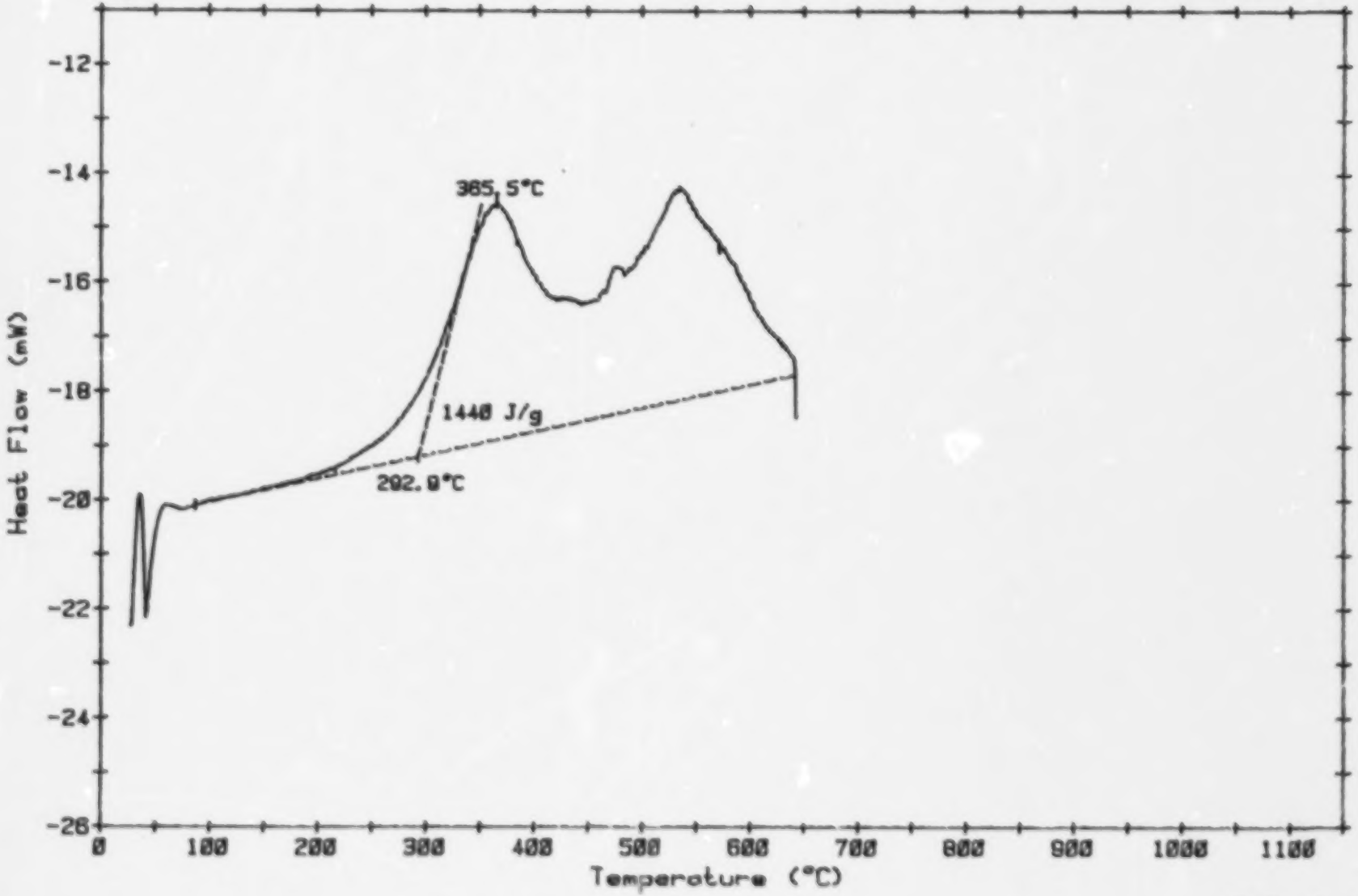


DuPont 1090

Sample: C
Size: 6.150 mg
Rate: 20.0DEG/MIN AIR
Program: Interactive DSC V2.0

DSC

Date: 15-Feb-85 Time: 9:13:44
File: C.02 DRC 12
Operator: GN
Plotted: 15-Feb-85 13:40:24

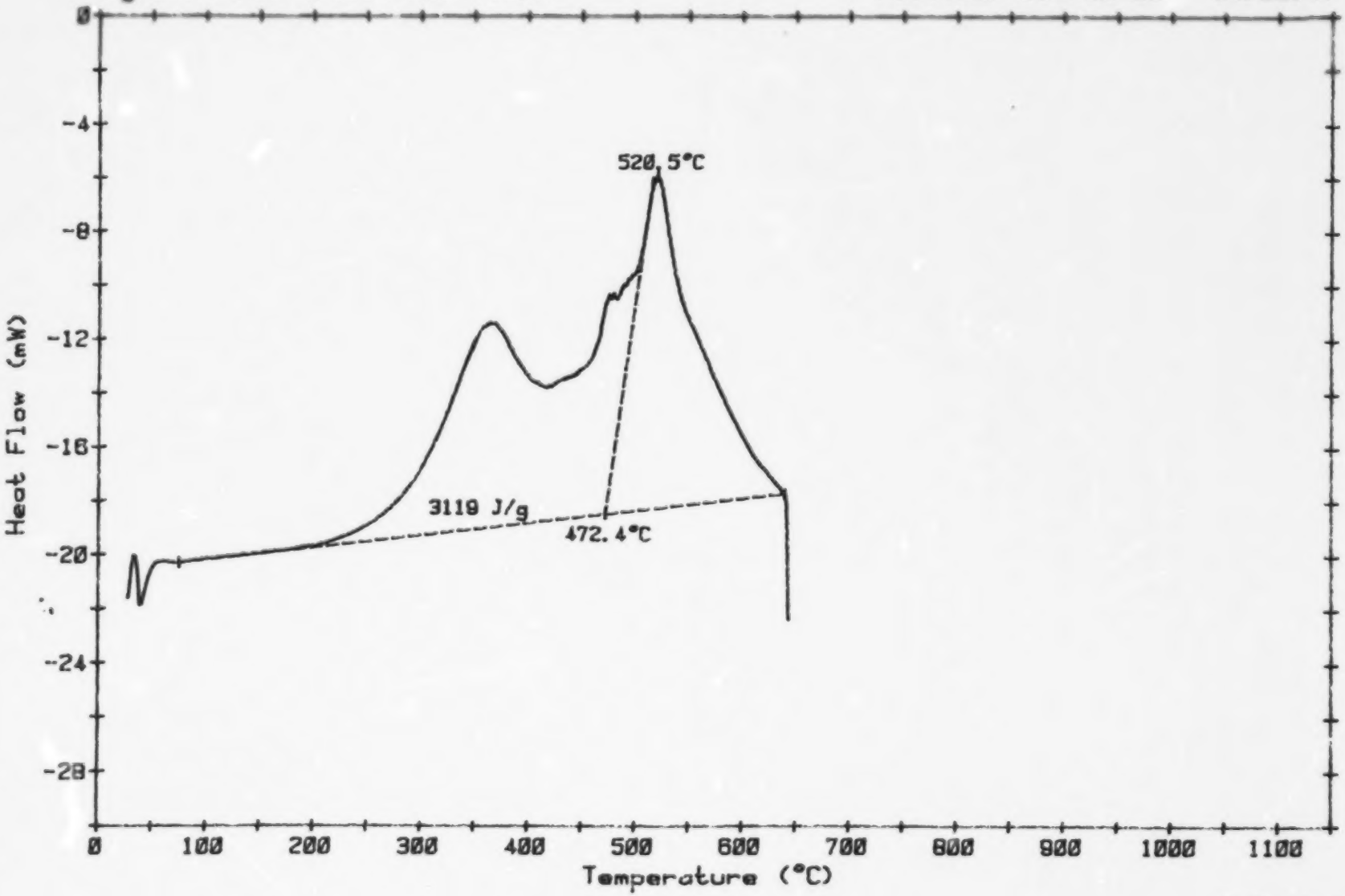


DuPont 1090

Sample: D
Size: 6.050 mg
Rate: 20.0DEG/MIN AIR
Program: Interactive DSC V2.0

DSC

Date: 15-Feb-85 Time: 10:02:02
File: D.02 DRC 12
Operator: GN
Plotted: 15-Feb-85 14:39:47

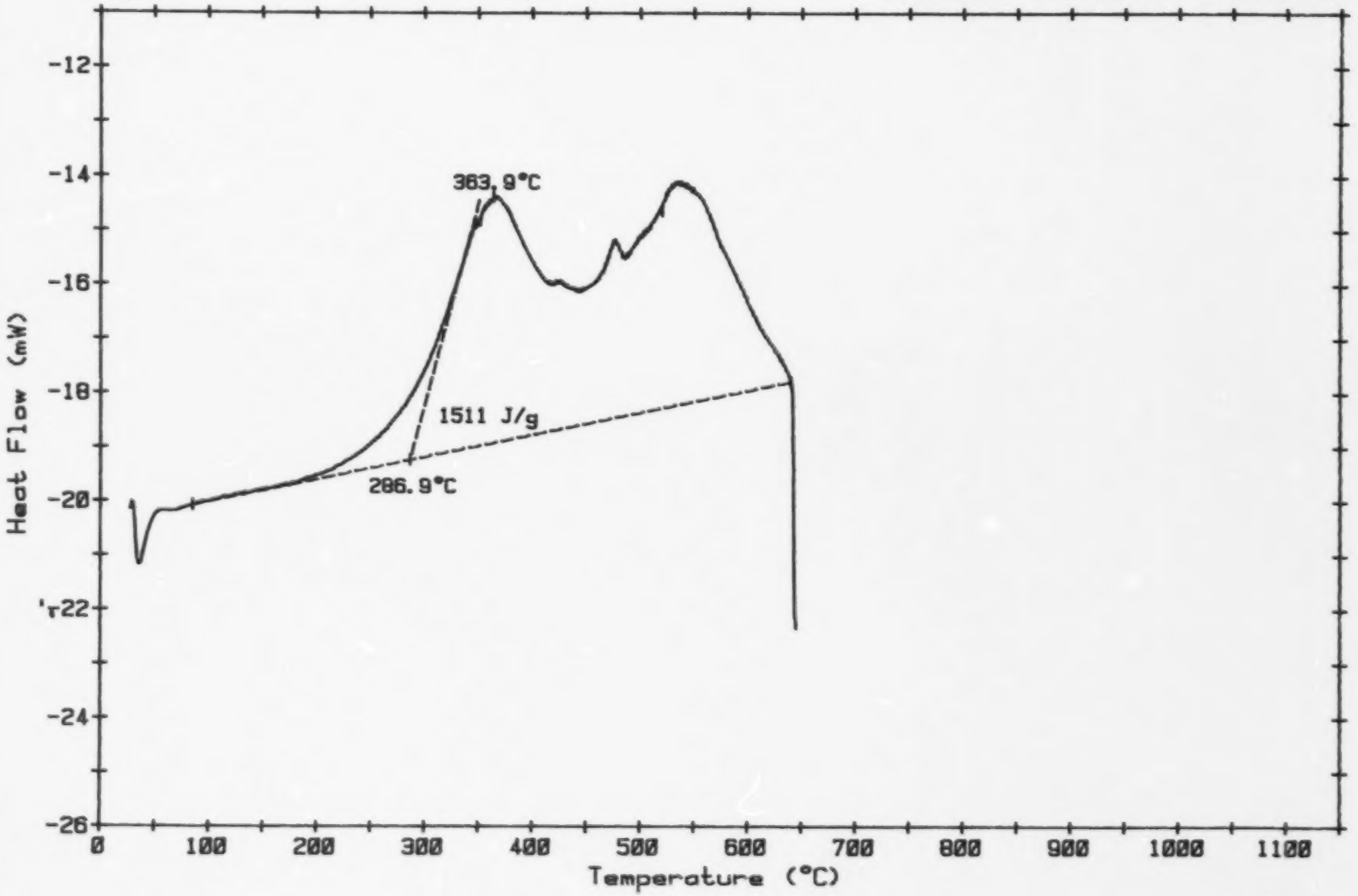


DuPont 1090

Sample: E
Size: 6.41MG
Rate: 20.0DEG/MIN AIR
Program: Interactive DSC V2.0

DSC

Date: 18-Feb-85 Time: 11:45:25
File: E.03 DRC 12
Operator: GN
Plotted: 18-Feb-85 13:50:33

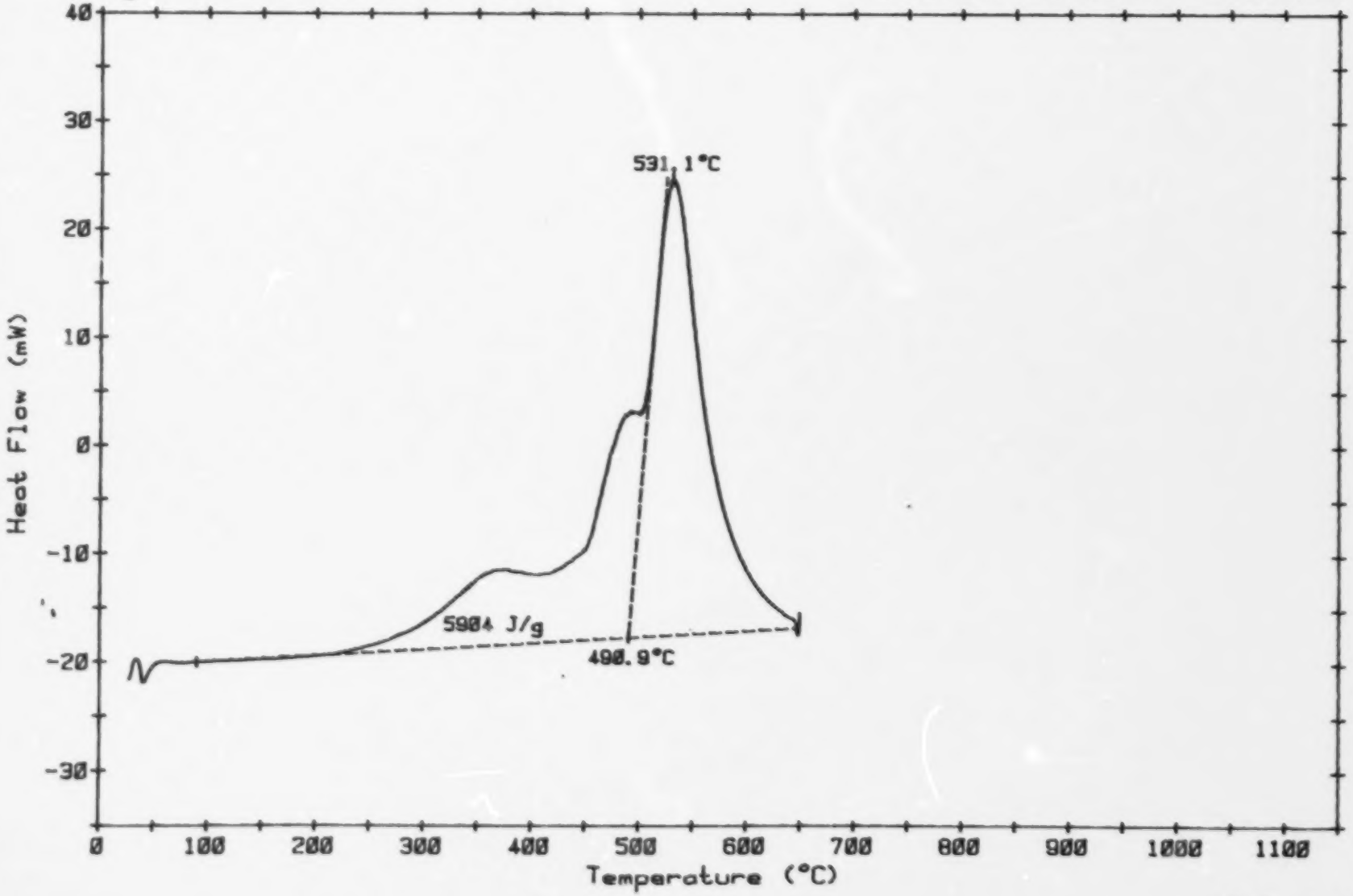


DuPont 1090

Sample: BB-1
Size: 6.690 mg
Rate: 20.0DEG/MIN AIR
Program: Interactive DSC V2.0

DSC

Date: 14-Feb-85 Time: 14:08:57
File: BB1.02 DRC 12
Operator: GN
Plotted: 14-Feb-85 15:39:02

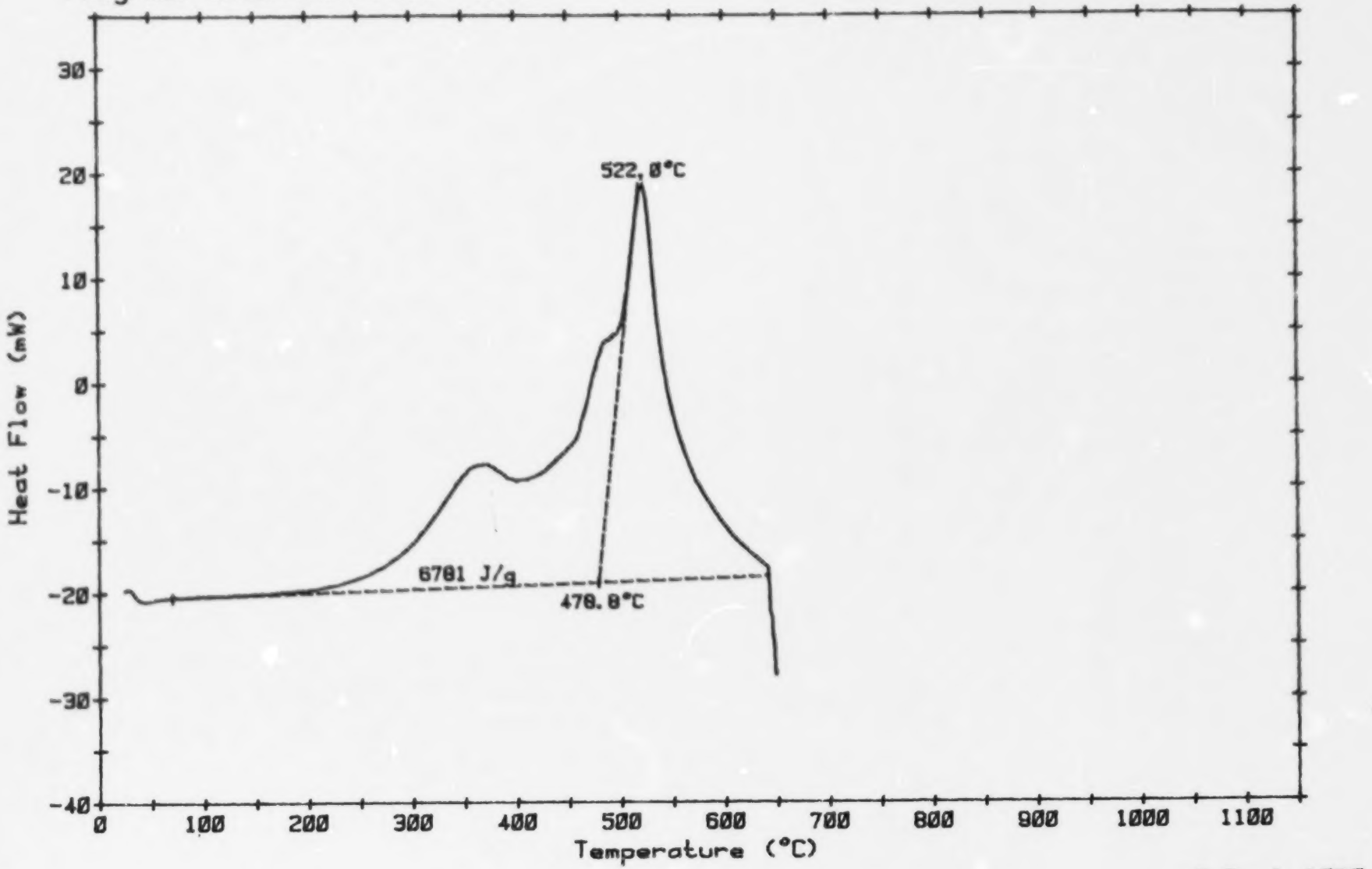


DuPont 1090

Sample: BB-2
Size: 6.260 mg
Rate: 20.0DEG/MIN AIR
Program: Interactive DSC V2.0

DSC

Date: 14-Feb-85 Time: 14:54:32
File: BB2.02 DRC 12
Operator: GN
Plotted: 15-Feb-85 8:26:47

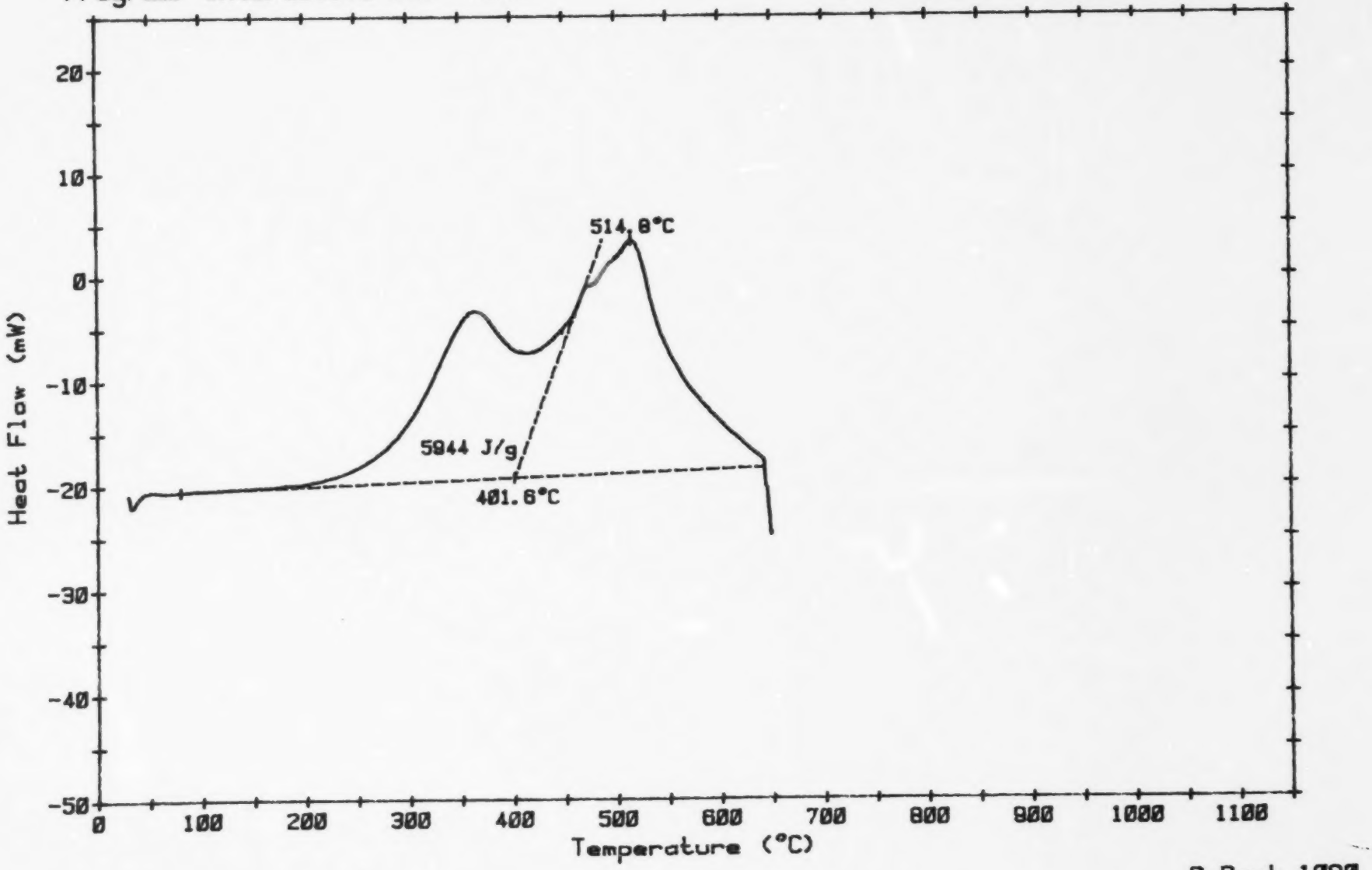


DuPont 1090

Sample: BB-3
Size: 6.800 mg
Rate: 20.0DEG/MIN AIR
Program: Interactive DSC V2.0

DSC

Date: 14-Feb-85 Time: 15:35:07
File: BB3.02 DRC 12
Operator: GN
Plotted: 15-Feb-85 9:23:18

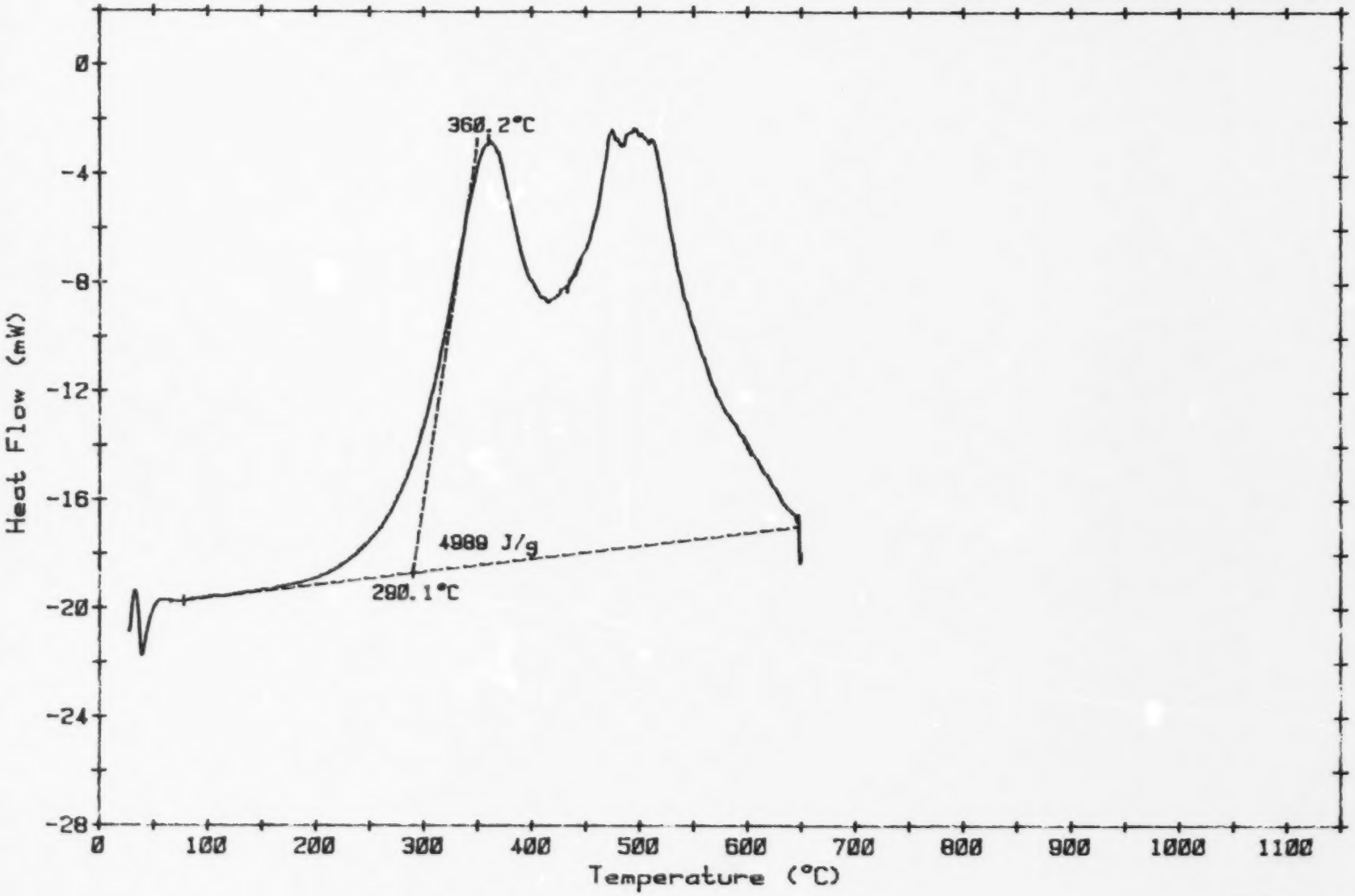


DuPont 1090

Sample: BB-4
Size: 6.500 mg
Rate: 20.0DEG/MIN AIR
Program: Interactive DSC V2.0

DSC

Date: 15-Feb-85 Time: 8:18:48
File: BB4.02 DRC 12
Operator: GN
Plotted: 15-Feb-85 11:34:06



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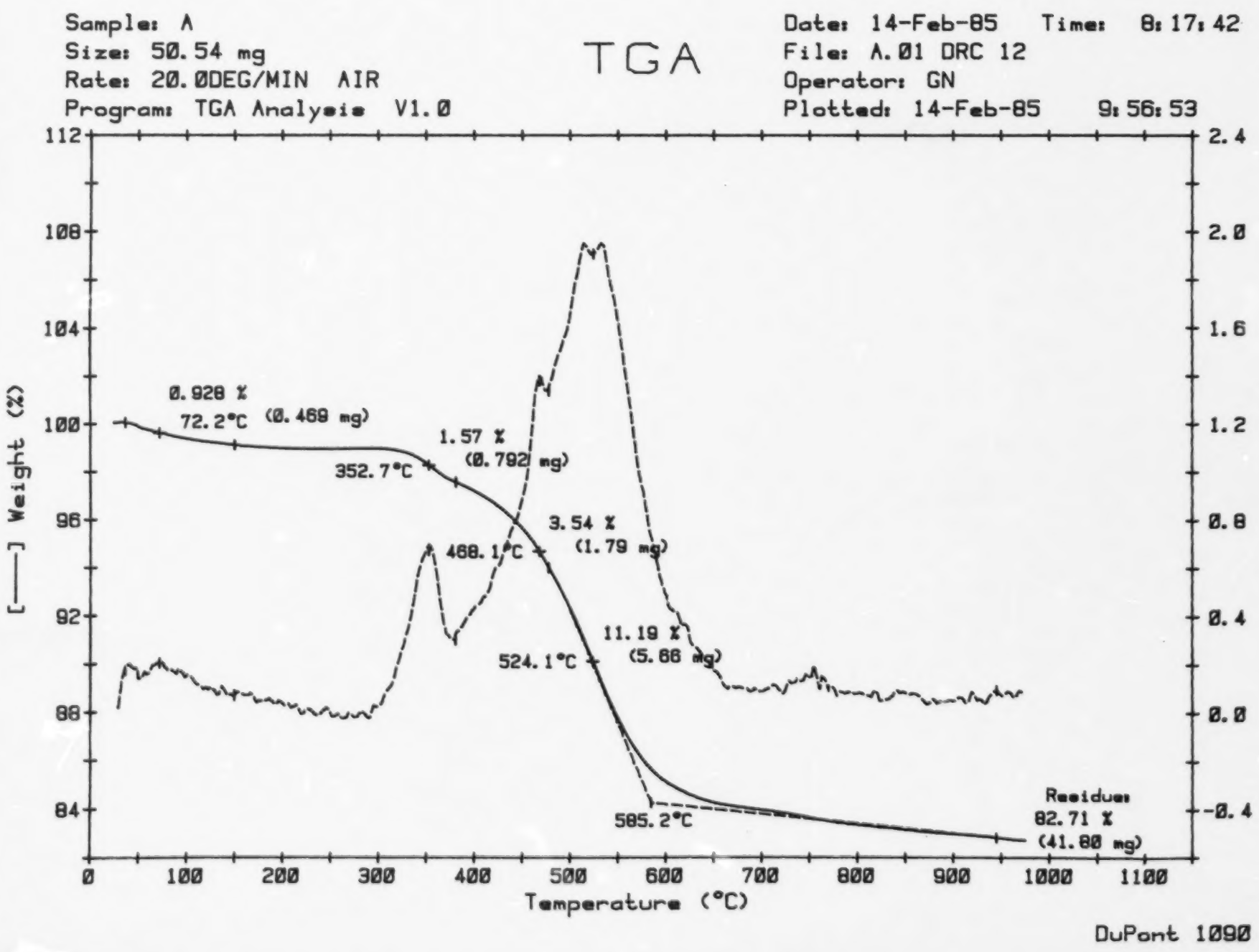
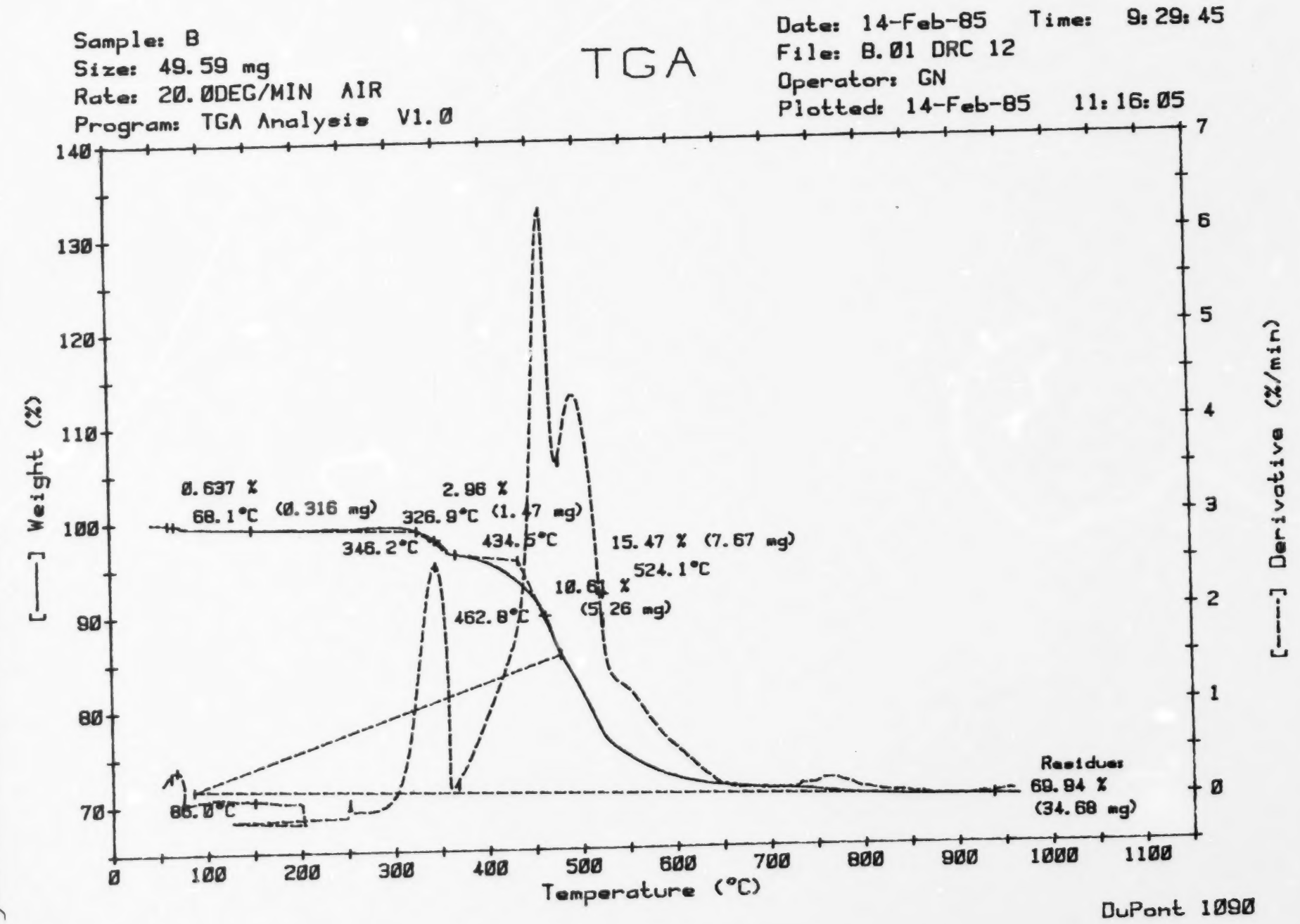

Sample: A
Size: 50.54 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0
TGA
Date: 14-Feb-85 Time: 8:17:42
File: A.01 DRC 12
Operator: GN
Plotted: 14-Feb-85 9:56:53
0.928 %
72.2°C (0.469 mg)
1.57 %
(0.792 mg)
352.7°C
3.54 %
(1.79 mg)
468.1°C
11.19 %
(5.66 mg)
524.1°C
585.2°C
Residue
82.71 %
(41.80 mg)
[——] Weight (%)
[----] Derivative (%/min)
Temperature (°C)
DuPont 1090

Sample: A
Size: 50.54 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0

Date: 14-Feb-85 Time: 8:17:42
File: A.01 DRC 12
Operator: GN
Plotted: 14-Feb-85 10:28:39

Transition	Onset [°C]	Inflection [°C]	Completion [°C]	Weight [mg]	Weight [%]
		72.2		0.47	0.93
		352.7		0.79	1.57
		468.1		1.79	3.54
		524.1	585.2	5.66	11.19
	Residue at	975.3 °C		41.80	82.71

Modified Sample Weight: 50.54 mg

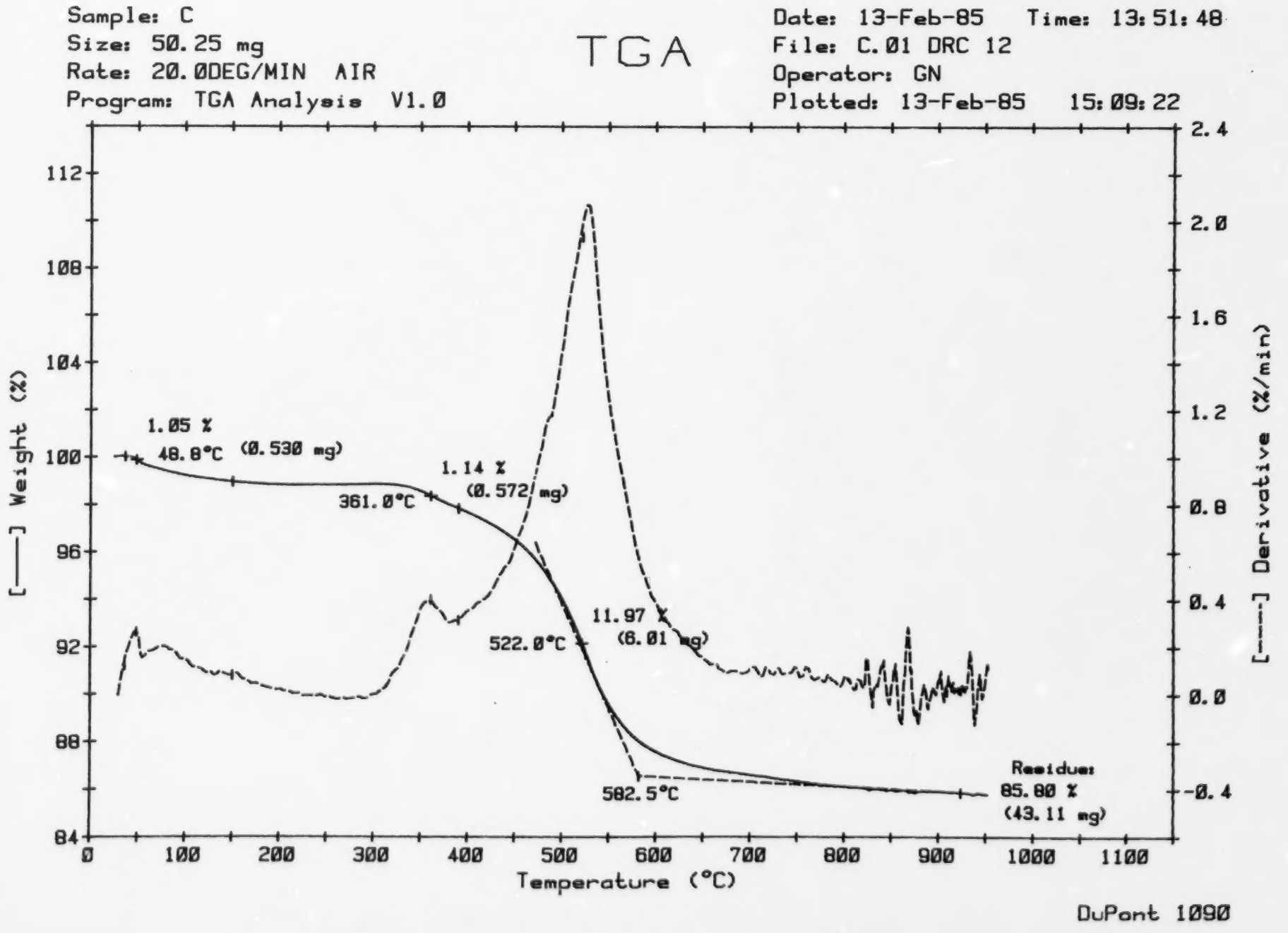

Sample: B
Size: 49.59 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0
TGA
Date: 14-Feb-85 Time: 9:29:45
File: B.01 DRC 12
Operator: GN
Plotted: 14-Feb-85 11:16:05
0.637 %
68.1°C (0.316 mg)
2.96 %
326.9°C (1.47 mg)
346.2°C
434.5°C
15.47 % (7.67 mg)
524.1°C
10.61 %
(5.26 mg)
462.8°C
86.0°C
Residue:
69.94 %
(34.68 mg)
[——] Weight (%)
[----] Derivative (%/min)
Temperature (°C)
DuPont 1090

Sample: B
Size: 49.59 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0

Date: 14-Feb-85 Time: 9:29:45
File: B.01 DRC 12
Operator: GN
Plotted: 14-Feb-85 10:59:33

Transition	Onset [°C]	Inflection [°C]	Completion [°C]	Weight [mg]	Weight [%]
		68.1		0.32	0.64
	326.9	346.2		1.47	2.96
	434.5	462.8		5.26	10.61
		524.1	86.0	7.67	15.47
	Residue at 965.6 °C			34.68	69.94

Modified Sample Weight: 49.59 mg

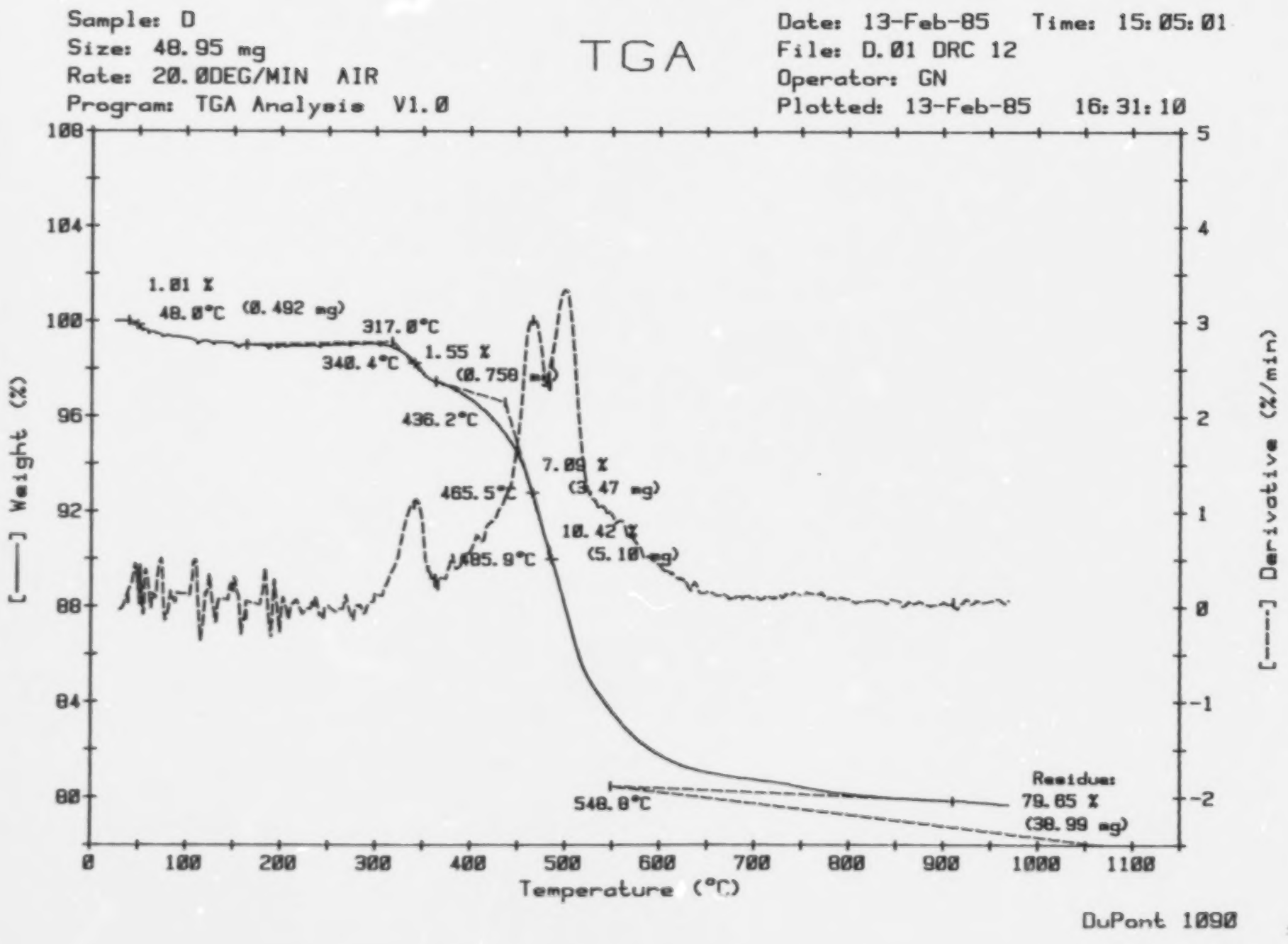

Sample: C
Size: 50.25 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0
TGA
Date: 13-Feb-85 Time: 13:51:48
File: C.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 15:09:22
1.05 %
48.8°C (0.530 mg)
361.0°C
1.14 %
(0.572 mg)
522.0°C
11.97 %
(6.01 mg)
582.5°C
Residue:
85.80 %
(43.11 mg)
[——] Weight (%)
[----] Derivative (%/min)
Temperature (°C)
DuPont 1090

Sample: C
Size: 50.25 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0

Date: 13-Feb-85 Time: 13:51:48
File: C.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 15:31:13

Transition	Onset [°C]	Inflection [°C]	Completion [°C]	Weight [mg]	Weight [%]
		48.8		0.53	1.05
		361.0		0.57	1.14
		522.0	582.5	6.01	11.97
	Residue at	957.0 °C		43.11	85.80

Modified Sample Weight: 50.25 mg

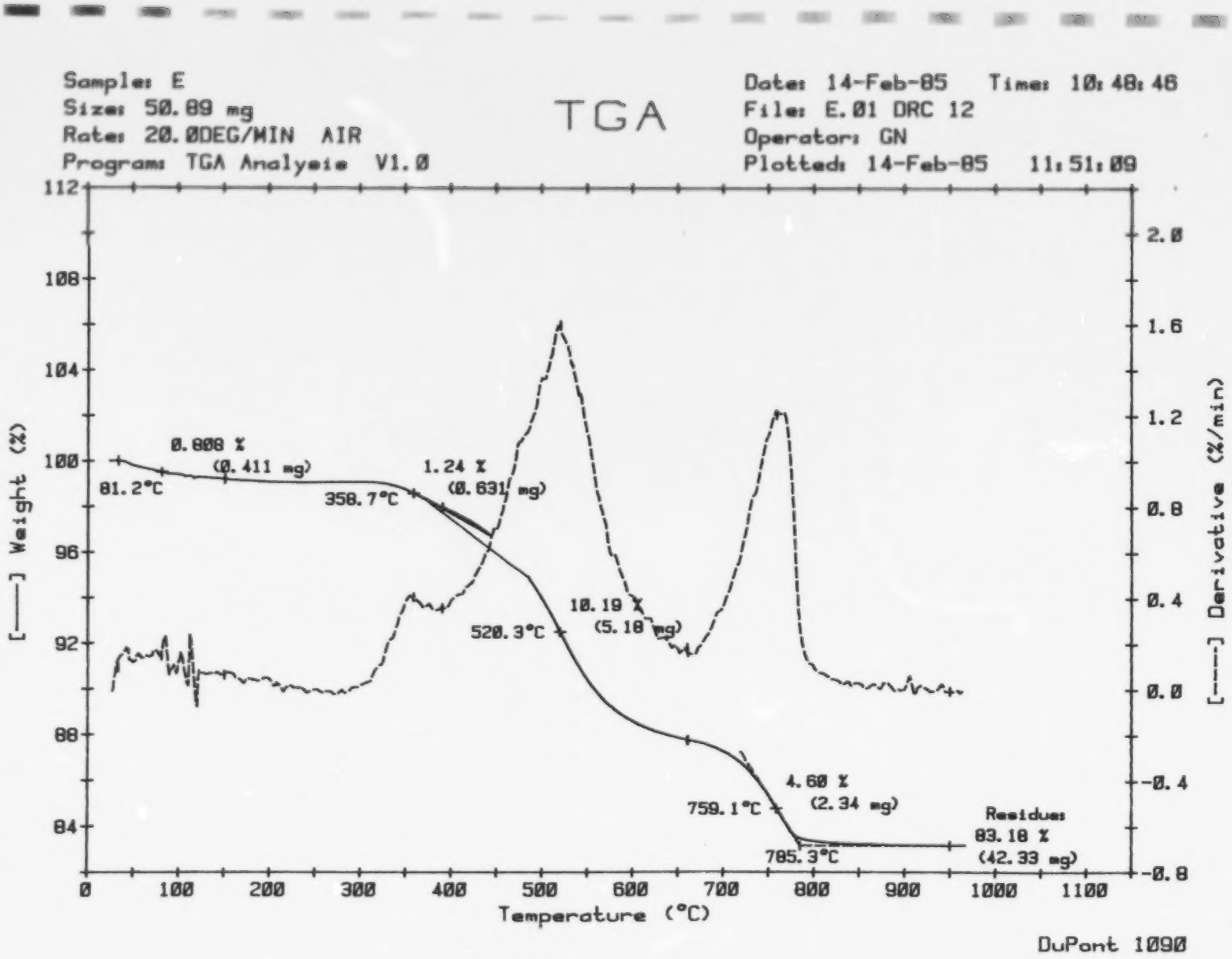

Sample: D
Size: 48.95 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0
TGA
Date: 13-Feb-85 Time: 15:05:01
File: D.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 16:31:10
1.01 %
48.0°C (0.492 mg)
317.0°C
348.4°C
1.55 %
(0.758 mg)
436.2°C
7.09 %
(3.47 mg)
465.5°C
10.42 %
(5.10 mg)
485.9°C
548.0°C
Residue:
78.65 %
(38.99 mg)
[——] Weight (%)
[----] Derivative (%/min)
Temperature (°C)
DuPont 1090

Sample: D
Size: 48.95 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0

Date: 13-Feb-85 Time: 15:05:01
File: D.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 16:22:21

Transition	Onset [°C]	Inflection [°C]	Completion [°C]	Weight [mg]	Weight [%]
		48.0		0.49	1.01
	317.0	340.4		0.76	1.55
	436.2	465.5		3.47	7.09
		485.9	548.8	5.10	10.42
	Residue at 973.8 °C			38.99	79.65

Modified Sample Weight: 48.95 mg

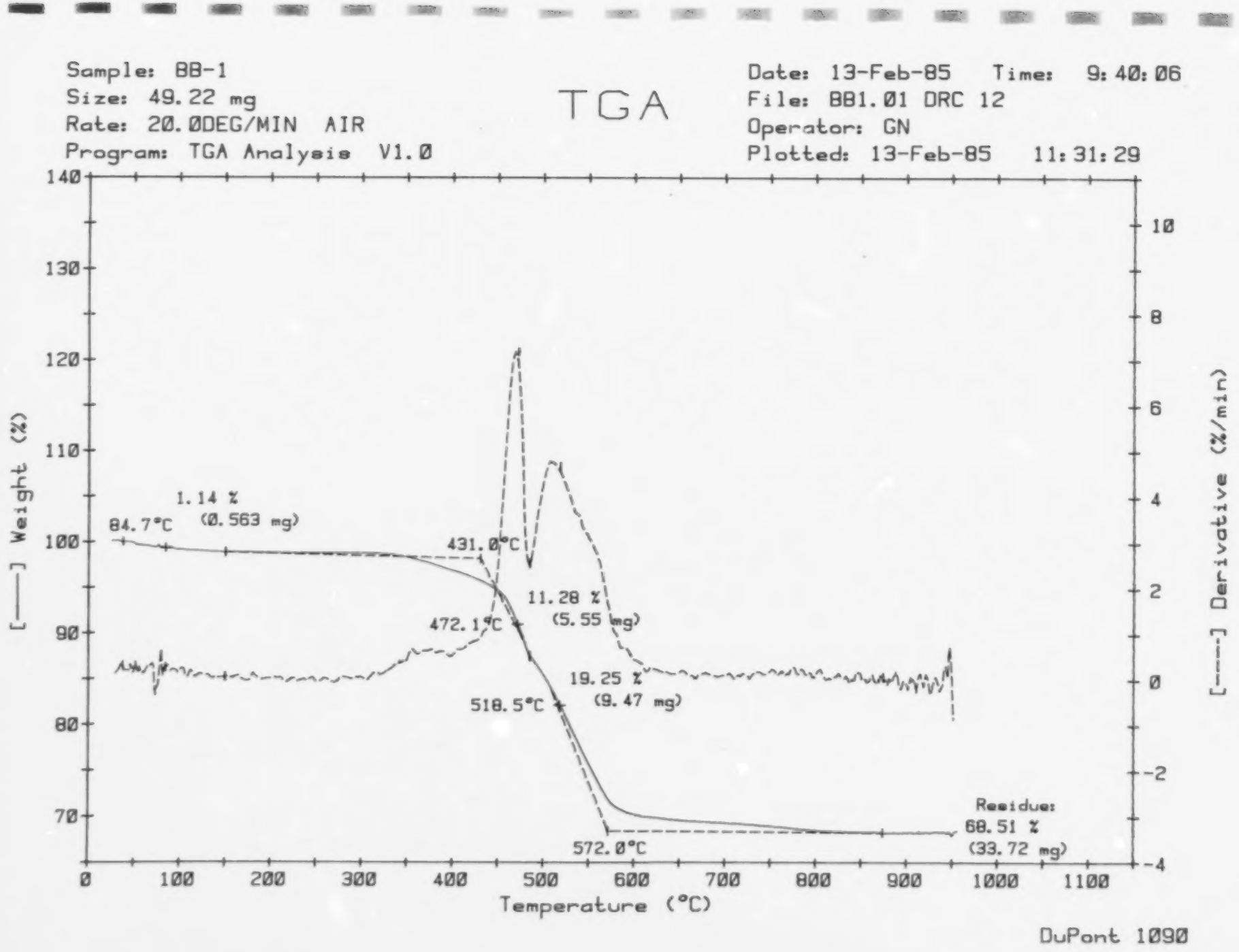

Sample: E
Size: 50.89 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0
TGA
Date: 14-Feb-85 Time: 10:48:46
File: E.01 DRC 12
Operator: GN
Plotted: 14-Feb-85 11:51:09
0.808 %
(0.411 mg)
81.2°C
358.7°C
1.24 %
(0.631 mg)
10.19 %
(5.18 mg)
520.3°C
4.60 %
(2.34 mg)
759.1°C
785.3°C
Residue:
83.18 %
(42.33 mg)
[——] Weight (%)
[----] Derivative (%/min)
Temperature (°C)
DuPont 1090

Sample: E
Size: 50.89 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0

Date: 14-Feb-85 Time: 10:48:46
File: E.01 DRC 12
Operator: GN
Plotted: 14-Feb-85 11:55:42

Transition	Onset [°C]	Inflection [°C]	Completion [°C]	Weight [mg]	Weight [%]
		81.2		0.41	0.81
		358.7		0.63	1.24
		520.3		5.18	10.19
		759.1	785.3	2.34	4.60
	Residue at	968.6 °C		42.33	83.18

Modified Sample Weight: 50.89 mg

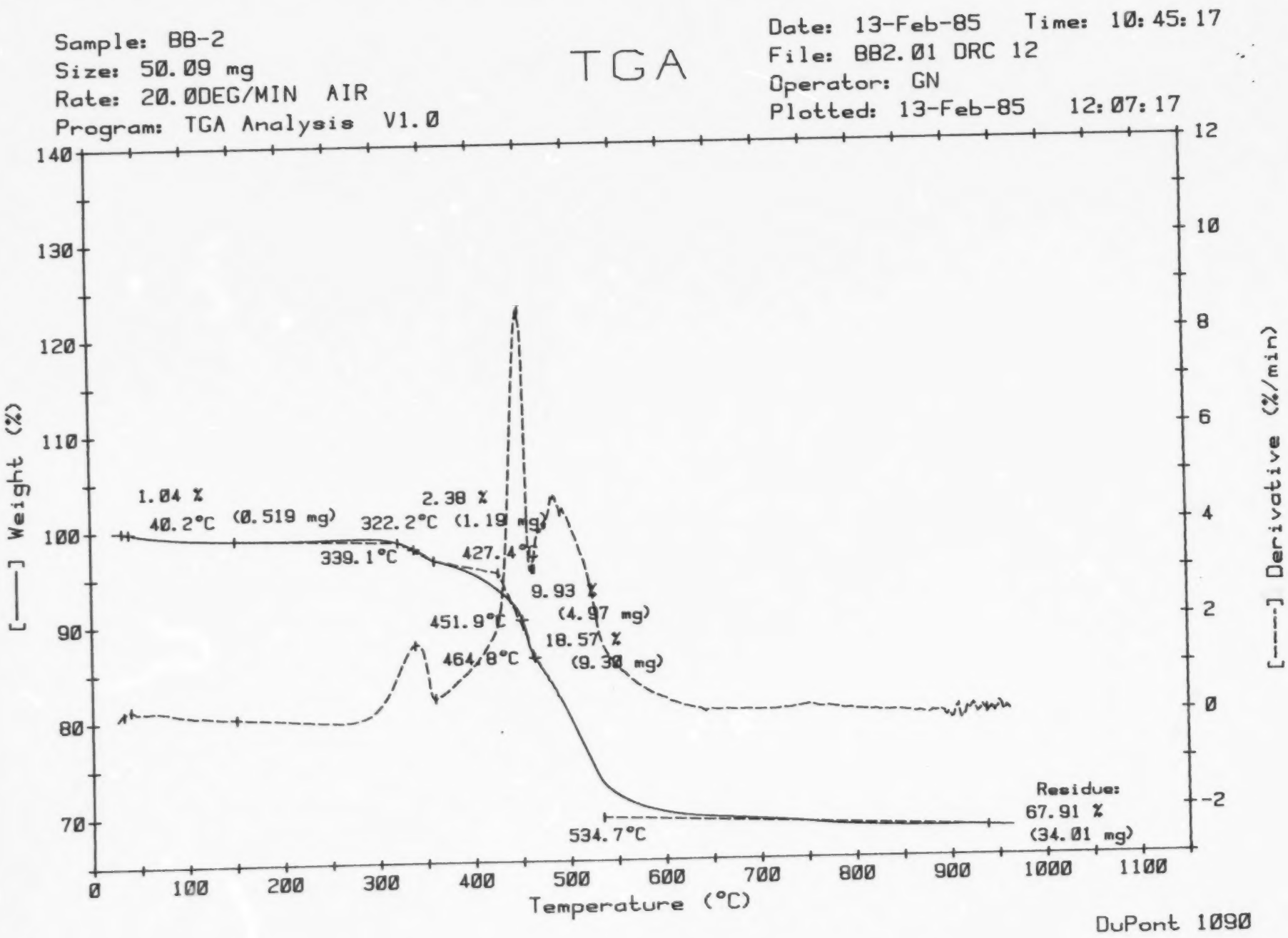

Sample: BB-1
Size: 49.22 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0
TGA
Date: 13-Feb-85 Time: 9:40:06
File: BB1.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 11:31:29
[——] Weight (%)
[----] Derivative (%/min)
Temperature (°C)
1.14 %
(0.563 mg)
84.7°C
431.0°C
11.28 %
(5.55 mg)
472.1°C
19.25 %
(9.47 mg)
518.5°C
572.0°C
Residue:
68.51 %
(33.72 mg)
DuPont 1090

Sample: BB-1
Size: 49.22 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0

Date: 13-Feb-85 Time: 9:40:06
File: BB1.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 11:34:32

Transition	Onset [°C]	Inflection [°C]	Completion [°C]	Weight [mg]	Weight [%]
		84.7		0.56	1.14
	431.0	472.1		5.55	11.28
		518.5	572.0	9.47	19.25
	Residue at 955.6 °C			33.72	68.51

Modified Sample Weight: 49.22 mg

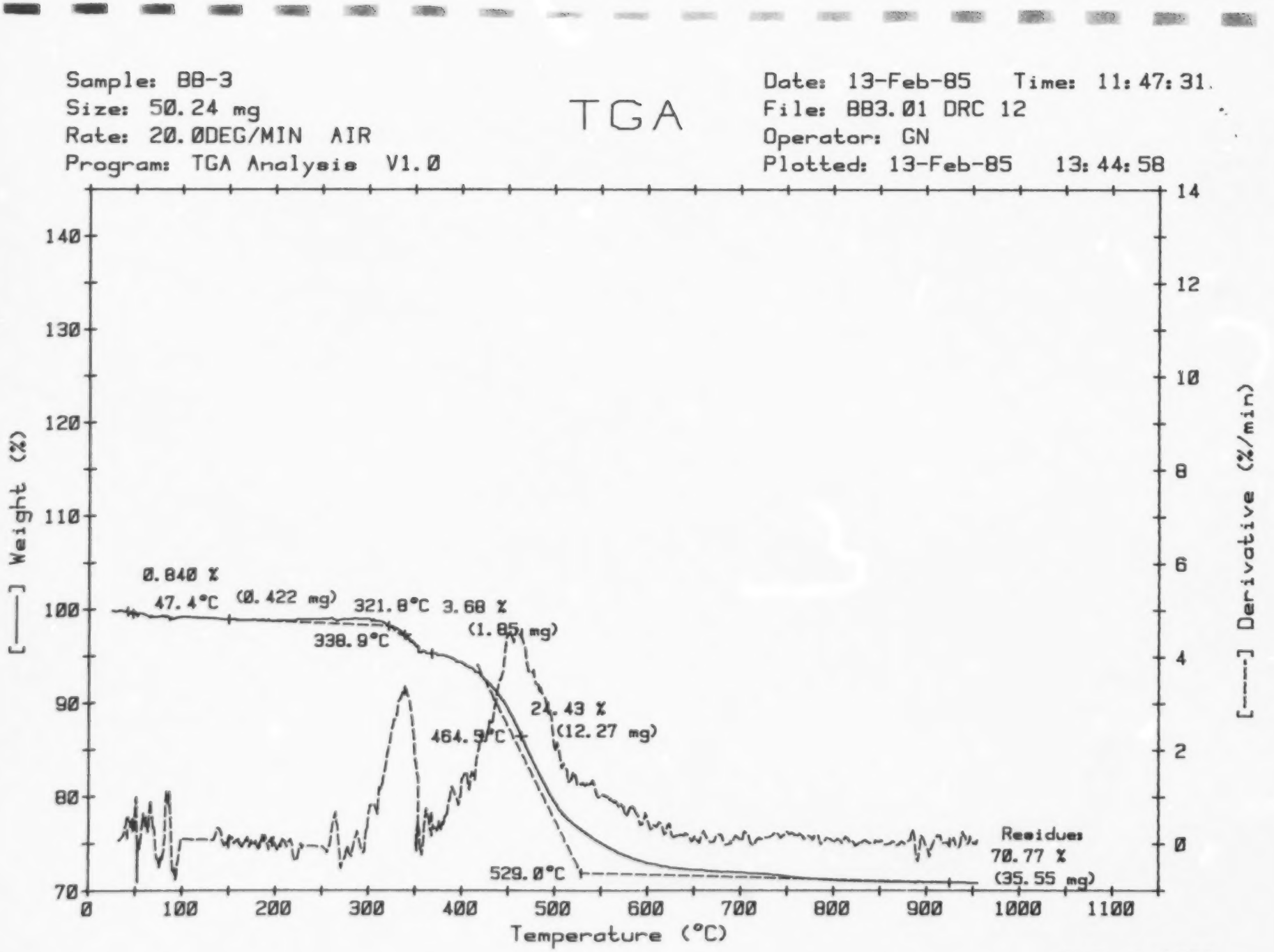

Sample: BB-2
Size: 50.09 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0
TGA
Date: 13-Feb-85 Time: 10:45:17
File: BB2.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 12:07:17
[——] Weight (%)
[----] Derivative (%/min)
Temperature (°C)
1.04 %
40.2°C (0.519 mg)
322.2°C
339.1°C
2.38 %
427.4°C
9.93 %
(4.97 mg)
451.9°C
18.57 %
464.8°C
(9.30 mg)
534.7°C
Residue:
67.91 %
(34.01 mg)
DuPont 1090

Sample: BB-2
Size: 50.09 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0

Date: 13-Feb-85 Time: 10:45:17
File: BB2.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 12:35:26

Transition	Onset [°C]	Inflection [°C]	Completion [°C]	Weight [mg]	Weight [%]
		40.2		0.52	1.04
	322.2	339.1		1.19	2.38
	427.4	451.9		4.97	9.93
		464.8	534.7	9.30	18.57
	Residue at 967.1 °C			34.01	67.91

Modified Sample Weight: 50.08 mg

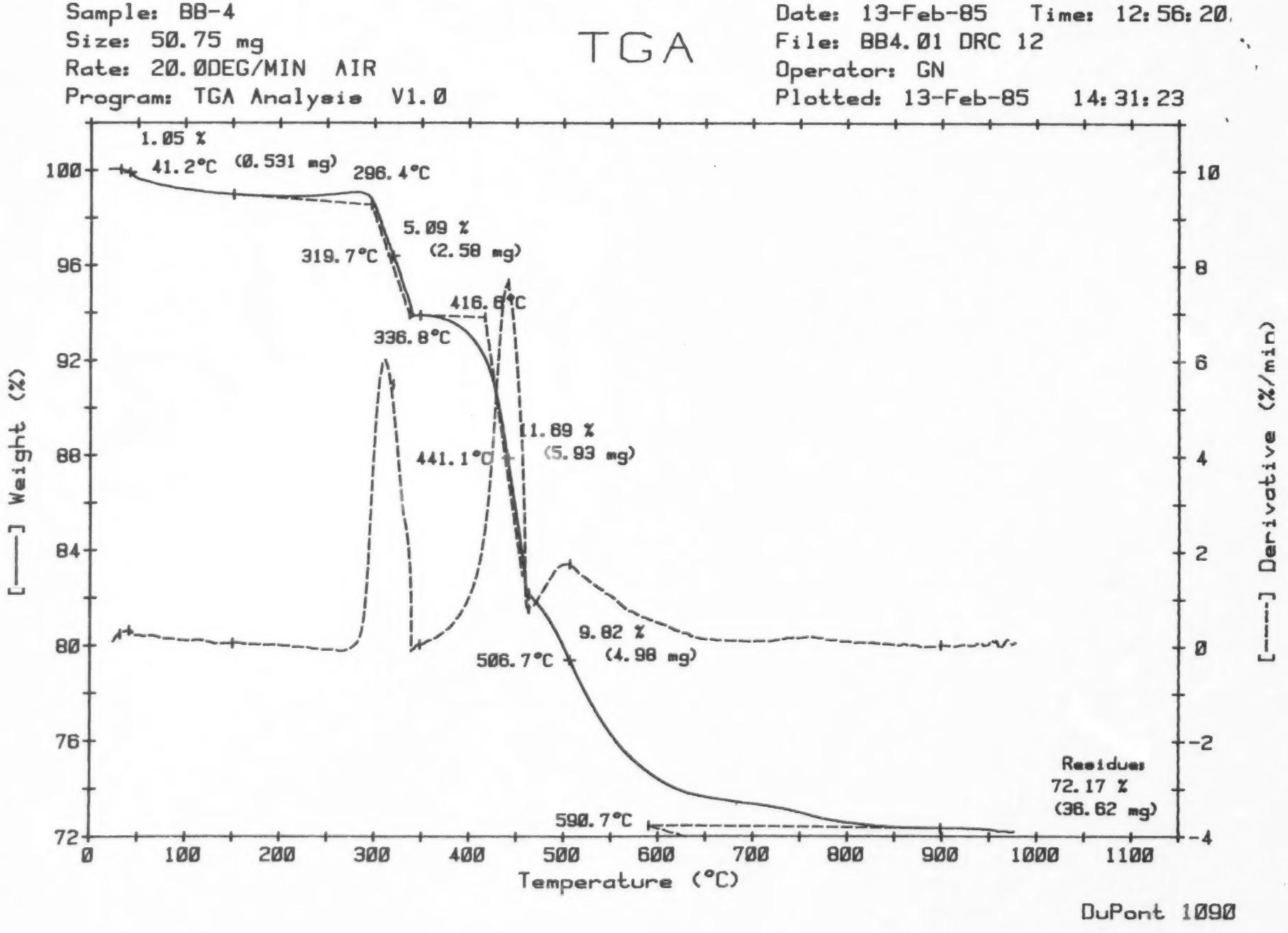

Sample: BB-3
Size: 50.24 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0
TGA
Date: 13-Feb-85 Time: 11:47:31
File: BB3.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 13:44:58
0.840 %
47.4°C (0.422 mg)
321.8°C 3.68 %
(1.85 mg)
338.9°C
24.43 %
(12.27 mg)
464.9°C
529.0°C
Residue:
70.77 %
(35.55 mg)
[——] Weight (%)
[----] Derivative (%/min)
Temperature (°C)
DuPont 1090

Sample: BB-3
Size: 50.24 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0

Date: 13-Feb-85 Time: 11:47:31
File: BB3.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 13:35:32

Transition	Onset [°C]	Inflection [°C]	Completion [°C]	Weight [mg]	Weight [%]
		47.4		0.42	0.84
	321.8	338.9		1.85	3.68
		464.5	529.0	12.27	24.43
	Residue at	960.0 °C		35.55	70.77

Modified Sample Weight: 50.24 mg


Sample: BB-4
Size: 50.75 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0
TGA
Date: 13-Feb-85 Time: 12:56:20
File: BB4.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 14:31:23
1.05 %
41.2°C (0.531 mg)
296.4°C
5.09 %
(2.58 mg)
319.7°C
416.6°C
336.8°C
11.69 %
(5.93 mg)
441.1°C
9.82 %
(4.98 mg)
506.7°C
Residue:
72.17 %
(36.62 mg)
590.7°C
[——] Weight (%)
[----] Derivative (%/min)
Temperature (°C)
DuPont 1090

Sample: BB-4
Size: 50.75 mg
Rate: 20.0DEG/MIN AIR
Program: TGA Analysis V1.0

Date: 13-Feb-85 Time: 12:56:20
File: BB4.01 DRC 12
Operator: GN
Plotted: 13-Feb-85 15:01:48

Transition	Onset [°C]	Inflection [°C]	Completion [°C]	Weight [mg]	Weight [%]
		41.2		0.53	1.05
	296.4	319.7	336.8	2.58	5.09
	416.6	441.1		5.93	11.69
		506.7	590.7	4.98	9.82
	Residue at 979.8 °C			36.62	72.17

Modified Sample Weight: 50.75 mg

APPENDIX A2

Hydrocarbon Profile of Oil Shale Zones

CORE LABORATORIES - CANADA LTD.

CALGARY, ALBERTA

CORE LABORATORIES-CANADA, LTD.

DATE: 1985 04 23

CHROMATOGRAPHIC ANALYSIS

1. Analysis: Extended Hydrocarbon Analysis

2. Instrument: Hewlett-Packard 5700

3. Column: 6' * 0.125" OD Chromosorb W. HP (80-100 Mesh)/3% OV-1

4. Instrument Conditions:

Detector: FID	Oven Temperature: -10 to 350°C @ 16°C/MIN.
Detector Temperature: 350°C	Carrier Gas: Helium
Injector: Flash Vaporization	Flow Rate: 20 MLS/MIN
Injector Temperature: 250°C	Detector Conditions: (H_2: 20 MLS/MIN)
Valves: None	(Air: 240 MLS/MIN)
Valve Temperature: N/A	Sample Size: 2.0 µl
	Analysis Time: 60 MIN.

5. Resolution:

Component	Retention Time (Minutes)	Component	Retention Time (Minutes)
NC2	0.5	NC22	16.2
NC4	0.8	NC24	17.2
NC6	2.5	NC26	18.2
NC8	5.0	NC28	19.1
NC10	7.3	NC30	19.9
NC12	9.2		
NC14	10.9		
NC16	12.4		
NC18	13.8		
NC20	15.0		

Core Laboratories-Canada, Ltd.
Date: 1985 04 23

6. Response

Chromatographic Analysis

Component	Carbon Number	Molecular Mass	Relative Response Factor
Methane	C1	16.0431	1.1437
Ethane	C2	30.0702	1.0719
Propane	C3	44.0973	1.0479
Iso Butane	C4	58.1244	1.0359
Normal Butane	C4	58.1244	1.0359
Iso Pentane	C5	72.1515	1.0287
Normal Pentane	C5	72.1515	1.0287
Hexanes	C6	86.1786	1.0240
Heptanes	C7	100.2057	1.0205
Octanes	C8	114.2328	1.0180
Nonanes	C9	128.2599	1.0160
Decanes	C10	142.2870	1.0144
Undecanes	C11	156.3141	1.0131
Dodecanes	C12	170.3412	1.0120
Tridecanes	C13	184.3683	1.0111
Tetradecanes	C14	198.3954	1.0103
Pentadecanes	C15	212.4225	1.0096
Hexadecanes	C16	226.4496	1.0090
Heptadecanes	C17	240.4767	1.0085
Octadecanes	C18	254.5038	1.0080
Nonadecanes	C19	268.5309	1.0076
Eicosanes	C20	282.5580	1.0072
Heneicosanes	C21	296.5851	1.0068
Docosanes	C22	310.6122	1.0065
Tricosanes	C23	324.6393	1.0062
Tetracosanes	C24	338.6664	1.0060
Pentacosanes	C25	352.6935	1.0057
Hexacosanes	C26	366.7206	1.0055
Heptacosanes	C27	380.7477	1.0053
Octacosanes	C28	394.7748	1.0051
Nonacosanes	C29	408.8019	1.0050
Triacontanes Plus	C30+	600.0000	1.0041
Benzene	C6H6	78.1146	0.9281
Toluene	C7H8	92.1417	0.9384
Ethylbenzene, p & m-Xylene	C8H10	106.1688	0.9461
o-Xylene	C8H10	106.1688	0.9461
1,2,4 Trimethylbenzene	C9H12	120.1959	0.9521
Cyclopentane	C5H10	70.1355	1.0000
Methylcyclopentane	C6H12	84.1626	1.0000
Cyclohexane	C6H12	84.1626	1.0000
Methylcyclohexane	C7H14	98.1897	1.0000

CORE LABORATORIES-CANADA LTD.

COMPANY Technical University of Nova Scotia
LOCATION
SAMPLED FROM Extracted Oil From Oil Shales "A"

PAGE 1
FILE 7012-85-759
DATE 1985 04 23

Analysis to C30+

Boiling Point Range (C)	Component	Carbon Number	Mole Fraction	Mass Fraction
-161.7	Methane	C1	0.0000	0.0000
- 88.9	Ethane	C2	0.0000	0.0000
- 42.2	Propane	C3	0.0000	0.0000
- 11.7	Iso Butane	C4	0.0000	0.0000
- 0.6	Normal Butane	C4	0.0000	0.0000
27.8	Iso Pentane	C5	0.0000	0.0000
36.1	Normal Pentane	C5	0.0000	0.0000
36.1- 68.9	Hexanes	C6	0.0000	0.0000
68.9- 98.3	Heptanes	C7	0.0000	0.0000
98.3-125.6	Octanes	C8	0.0011	0.0005
125.6-150.6	Nonanes	C9	0.0155	0.0073
150.6-173.9	Decanes	C10	0.0481	0.0250
173.9-196.1	Undecanes	C11	0.0736	0.0420
196.1-215.0	Dodecanes	C12	0.0795	0.0495
215.0-235.0	Tridecanes	C13	0.0782	0.0527
235.0-252.2	Tetradecanes	C14	0.0742	0.0538
252.2-270.6	Pentadecanes	C15	0.0603	0.0468
270.6-287.8	Hexadecanes	C16	0.0585	0.0484
287.8-302.8	Heptadecanes	C17	0.0511	0.0449
302.8-317.2	Octadecanes	C18	0.0452	0.0421
317.2-330.0	Nonadecanes	C19	0.0421	0.0413
330.0-344.4	Eicosanes	C20	0.0360	0.0371
344.4-357.2	Heneicosanes	C21	0.0323	0.0350
357.2-369.4	Docosanes	C22	0.0307	0.0348
369.4-380.0	Tricosanes	C23	0.0274	0.0325
380.0-391.1	Tetracosanes	C24	0.0246	0.0304
391.1-401.7	Pentacosanes	C25	0.0227	0.0292
401.7-412.2	Hexacosanes	C26	0.0204	0.0273
412.2-422.2	Heptacosanes	C27	0.0193	0.0269
422.2-431.7	Octacosanes	C28	0.0173	0.0250
431.7-441.1	Nonacosanes	C29	0.0143	0.0213
441.1 PLUS	Triacontanes Plus	C30+	0.1086	0.2384
	AROMATICS			
80.0	Benzene	C6H6	0.0000	0.0000
110.6	Toluene	C7H8	0.0000	0.0000
136.1-138.9	Ethylbenzene, p + m-Xylene	C8H10	0.0045	0.0017
144.4	o-Xylene	C8H10	0.0045	0.0017
168.9	1,2,4 Trimethylbenzene	C9H12	0.0100	0.0044
	NAPHTHENES			
48.9	Cyclopentane	C5H10	0.0000	0.0000
72.2	Methylcyclopentane	C6H12	0.0000	0.0000
81.1	Cyclohexane	C6H12	0.0000	0.0000
101.1	Methylcyclohexane	C7H14	0.0000	0.0000
	TOTAL		1.0000	1.0000

The above hexanes plus values are based upon a measured mass fraction and a calculated mole fraction, and assume a total hydrocarbon recovery from the chromatographic system.

CORE LABORATORIES-CANADA LTD.

COMPANY Technical University of Nova Scotia
LOCATION
SAMPLED FROM Extracted Oil From Oil Shales "B"

PAGE 2
FILE 7012-85-759
DATE 1985 04 23

Analysis to C30+

Boiling Point Range (C)	Component	Carbon Number	Mole Fraction	Mass Fraction
-161.7	Methane	C1	0.0000	0.0000
- 88.9	Ethane	C2	0.0000	0.0000
- 42.2	Propane	C3	0.0000	0.0000
- 11.7	Iso Butane	C4	0.0000	0.0000
- 0.6	Normal Butane	C4	0.0000	0.0000
27.8	Iso Pentane	C5	0.0000	0.0000
36.1	Normal Pentane	C5	0.0000	0.0000
36.1- 68.9	Hexanes	C6	0.0000	0.0000
68.9- 98.3	Heptanes	C7	0.0003	0.0001
98.3-125.6	Octanes	C8	0.0215	0.0095
125.6-150.6	Nonanes	C9	0.0365	0.0181
150.6-173.9	Decanes	C10	0.0736	0.0406
173.9-196.1	Undecanes	C11	0.0786	0.0477
196.1-215.0	Dodecanes	C12	0.0743	0.0491
215.0-235.0	Tridecanes	C13	0.0729	0.0522
235.0-252.2	Tetradecanes	C14	0.0614	0.0473
252.2-270.6	Pentadecanes	C15	0.0581	0.0479
270.6-287.8	Hexadecanes	C16	0.0503	0.0442
287.8-302.8	Heptadecanes	C17	0.0459	0.0428
302.8-317.2	Octadecanes	C18	0.0422	0.0417
317.2-330.0	Nonadecanes	C19	0.0364	0.0380
330.0-344.4	Eicosanes	C20	0.0336	0.0368
344.4-357.2	Heneicosanes	C21	0.0311	0.0357
357.2-369.4	Docosanes	C22	0.0267	0.0322
369.4-380.0	Tricosanes	C23	0.0252	0.0318
380.0-391.1	Tetracosanes	C24	0.0207	0.0272
391.1-401.7	Pentacosanes	C25	0.0194	0.0265
401.7-412.2	Hexacosanes	C26	0.0172	0.0245
412.2-422.2	Heptacosanes	C27	0.0157	0.0232
422.2-431.7	Octacosanes	C28	0.0149	0.0228
431.7-441.1	Nonacosanes	C29	0.0127	0.0201
441.1 PLUS	Triacontanes Plus	C30+	0.0966	0.2254
	ARUMATICS			
80.0	Benzene	C6H6	0.0000	0.0000
110.6	Toluene	C7H8	0.0006	0.0002
136.1-138.9	Ethylbenzene, p + m-Xylene	C8H10	0.0110	0.0045
144.4	o-Xylene	C8H10	0.0095	0.0039
168.9	1,2,4 Trimethylbenzene	C9H12	0.0120	0.0056
	NAPHTHENES			
48.9	Cyclopentane	C5H10	0.0000	0.0000
72.2	Methylcyclopentane	C6H12	0.0000	0.0000
81.1	Cyclohexane	C6H12	0.0000	0.0000
101.1	Methylcyclohexane	C7H14	0.0011	0.0004
	TOTAL		1.0000	1.0000

The above hexanes plus values are based upon a measured mass fraction and a calculated mole fraction, and assume a total hydrocarbon recovery from the chromatographic system.

CORE LABORATORIES-CANADA LTD.

COMPANY Technical University of Nova Scotia
LOCATION
SAMPLED FROM Extracted Oil From Oil Shales "C"

PAGE 3
FILE 7012-85-759
DATE 1985 04 23

Analysis to C30+

Boiling Point Range (C)	Component	Carbon Number	Mole Fraction	Mass Fraction
-161.7	Methane	C1	0.0000	0.0000
- 88.9	Ethane	C2	0.0000	0.0000
- 42.2	Propane	C3	0.0000	0.0000
- 11.7	Iso Butane	C4	0.0000	0.0000
- 0.6	Normal Butane	C4	0.0000	0.0000
27.8	Iso Pentane	C5	0.0000	0.0000
36.1	Normal Pentane	C5	0.0000	0.0000
36.1- 68.9	Hexanes	C6	0.0007	0.0003
68.9- 98.3	Heptanes	C7	0.0049	0.0021
98.3-125.6	Octanes	C8	0.0497	0.0238
125.6-150.6	Nonanes	C9	0.0499	0.0269
150.6-173.9	Decanes	C10	0.0791	0.0473
173.9-196.1	Undecanes	C11	0.0847	0.0556
196.1-215.0	Dodecanes	C12	0.0737	0.0528
215.0-235.0	Tridecanes	C13	0.0720	0.0558
235.0-252.2	Tetradecanes	C14	0.0559	0.0466
252.2-270.6	Pentadecanes	C15	0.0558	0.0498
270.6-287.8	Hexadecanes	C16	0.0470	0.0447
287.8-302.8	Heptadecanes	C17	0.0427	0.0432
302.8-317.2	Octadecanes	C18	0.0368	0.0393
317.2-330.0	Nonadecanes	C19	0.0344	0.0388
330.0-344.4	Eicosanes	C20	0.0299	0.0355
344.4-357.2	Heneicosanes	C21	0.0277	0.0345
357.2-369.4	Docosanes	C22	0.0243	0.0317
369.4-380.0	Tricosanes	C23	0.0221	0.0302
380.0-391.1	Tetracosanes	C24	0.0196	0.0279
391.1-401.7	Pentacosanes	C25	0.0174	0.0258
401.7-412.2	Hexacosanes	C26	0.0158	0.0243
412.2-422.2	Heptacosanes	C27	0.0135	0.0215
422.2-431.7	Octacosanes	C28	0.0122	0.0202
431.7-441.1	Nonacosanes	C29	0.0106	0.0182
441.1 PLUS	Triacontanes Plus	C30+	0.0722	0.1819
	AROMATICS			
80.0	Benzene	C6H6	0.0007	0.0002
110.6	Toluene	C7H8	0.0018	0.0007
136.1-138.9	Ethylbenzene, p + m-Xylene	C8H10	0.0155	0.0069
144.4	o-Xylene	C8H10	0.0085	0.0038
168.9	1,2,4 Trimethylbenzene	C9H12	0.0114	0.0058
	NAPHTHENES			
48.9	Cyclopentane	C5H10	0.0000	0.0000
72.2	Methylcyclopentane	C6H12	0.0021	0.0008
81.1	Cyclohexane	C6H12	0.0007	0.0003
101.1	Methylcyclohexane	C7H14	0.0067	0.0028
	TOTAL		1.0000	1.0000

The above hexanes plus values are based upon a measured mass fraction and a calculated mole fraction, and assume a total hydrocarbon recovery from the chromatographic system.

CORE LABORATORIES-CANADA LTD.

COMPANY Technical University of Nova Scotia — PAGE 4
LOCATION — FILE 7012-85-759
SAMPLED FROM Extracted Oil From Oil Shales "D" — DATE 1985 04 23

Analysis to C30+

Boiling Point Range (C)	Component	Carbon Number	Mole Fraction	Mass Fraction
-161.7	Methane	C1	0.0000	0.0000
- 88.9	Ethane	C2	0.0000	0.0000
- 42.2	Propane	C3	0.0000	0.0000
- 11.7	Iso Butane	C4	0.0000	0.0000
- 0.6	Normal Butane	C4	0.0000	0.0000
27.8	Iso Pentane	C5	0.0008	0.0002
36.1	Normal Pentane	C5	0.0004	0.0001
36.1- 68.9	Hexanes	C6	0.0061	0.0023
68.9- 98.3	Heptanes	C7	0.0301	0.0130
98.3-125.6	Octanes	C8	0.0692	0.0339
125.6-150.6	Nonanes	C9	0.0525	0.0289
150.6-173.9	Decanes	C10	0.0639	0.0390
173.9-196.1	Undecanes	C11	0.0757	0.0507
196.1-215.0	Dodecanes	C12	0.0668	0.0488
215.0-235.0	Tridecanes	C13	0.0623	0.0492
235.0-252.2	Tetradecanes	C14	0.0528	0.0449
252.2-270.6	Pentadecanes	C15	0.0488	0.0444
270.6-287.8	Hexadecanes	C16	0.0436	0.0423
287.8-302.8	Heptadecanes	C17	0.0369	0.0381
302.8-317.2	Octadecanes	C18	0.0342	0.0373
317.2-330.0	Nonadecanes	C19	0.0322	0.0371
330.0-344.4	Eicosanes	C20	0.0273	0.0331
344.4-357.2	Heneicosanes	C21	0.0254	0.0324
357.2-369.4	Docosanes	C22	0.0225	0.0300
369.4-380.0	Tricosanes	C23	0.0212	0.0295
380.0-391.1	Tetracosanes	C24	0.0187	0.0272
391.1-401.7	Pentacosanes	C25	0.0164	0.0248
401.7-412.2	Hexacosanes	C26	0.0143	0.0225
412.2-422.2	Heptacosanes	C27	0.0125	0.0204
422.2-431.7	Octacosanes	C28	0.0118	0.0199
431.7-441.1	Nonacosanes	C29	0.0111	0.0194
441.1 PLUS	Triacontanes Plus	C30+	0.0784	0.2024
	ARUMATICS			
80.0	Benzene	C6H6	0.0010	0.0003
110.6	Toluene	C7H8	0.0022	0.0009
136.1-138.9	Ethylbenzene, p + m-Xylene	C8H10	0.0165	0.0075
144.4	o-Xylene	C8H10	0.0102	0.0046
168.9	1,2,4 Trimethylbenzene	C9H12	0.0116	0.0060
	NAPHTHENES			
48.9	Cyclopentane	C5H10	0.0004	0.0001
72.2	Methylcyclopentane	C6H12	0.0065	0.0023
81.1	Cyclohexane	C6H12	0.0019	0.0007
101.1	Methylcyclohexane	C7H14	0.0138	0.0058
	TOTAL		1.0000	1.0000

The above hexanes plus values are based upon a measured mass fraction and a calculated mole fraction, and assume a total hydrocarbon recovery from the chromatographic system.

APPENDIX A3

Hydrocarbon Profile of Upgraded Oil Shale Zone C

CORE LABORATORIES-CANADA LTD.

COMPANY Technical University of Nova Scotia
LOCATION
SAMPLED FROM Oil From Tailings

FILE 70380-86-18
DATE 1986 01 06

Analysis to C30+

Boiling Point Range (C)	Component	Carbon Number	Mole Fraction	Mass Fraction
-161.7	Methane	C1	0.0000	0.0000
- 88.9	Ethane	C2	0.0000	0.0000
- 42.2	Propane	C3	0.0000	0.0000
- 11.7	Iso Butane	C4	0.0000	0.0000
- 0.6	Normal Butane	C4	0.0000	0.0000
27.8	Iso Pentane	C5	0.0000	0.0000
36.1	Normal Pentane	C5	0.0003	0.0001
36.1- 68.9	Hexanes	C6	0.0030	0.0012
68.9- 98.3	Heptanes	C7	0.0106	0.0048
98.3-125.6	Octanes	C8	0.0252	0.0130
125.6-150.6	Nonanes	C9	0.0316	0.0183
150.6-173.9	Decanes	C10	0.0406	0.0261
173.9-196.1	Undecanes	C11	0.0701	0.0495
196.1-215.0	Dodecanes	C12	0.0786	0.0605
215.0-235.0	Tridecanes	C13	0.1335	0.1111
235.0-252.2	Tetradecanes	C14	0.1053	0.0944
252.2-270.6	Pentadecanes	C15	0.0684	0.0657
270.6-287.8	Hexadecanes	C16	0.0576	0.0590
287.8-302.8	Heptadecanes	C17	0.0484	0.0526
302.8-317.2	Octadecanes	C18	0.0454	0.0523
317.2-330.0	Nonadecanes	C19	0.0452	0.0549
330.0-344.4	Eicosanes	C20	0.0320	0.0409
344.4-357.2	Heneicosanes	C21	0.0283	0.0379
357.2-369.4	Docosanes	C22	0.0234	0.0329
369.4-380,0	Tricosanes	C23	0.0197	0.0289
380.0-391.1	Tetracosanes	C24	0.0161	0.0246
391.1-401.7	Pentacosanes	C25	0.0141	0.0224
401.7-412.2	Hexacosanes	C26	0.0103	0.0171
412.2-422.2	Heptacosanes	C27	0.0096	0.0164
422.2-431.7	Octacosanes	C28	0.0070	0.0124
431.7-441.1	Nonacosanes	C29	0.0059	0.0110
441.1 PLUS	Triacontanes Plus	C30+	0.0262	0.0713
	AROMATICS			
80.0	Benzene	C6H6	0.0010	0.0003
110.6	Toluene	C7H8	0.0060	0.0025
136.1-138.9	Ethylbenzene, p + m-Xylene	C8H10	0.0159	0.0077
144.4	o-Xylene	C8H10	0.0059	0.0028
168.9	1,2,4 Trimethylbenzene	C9H12	0.0101	0.0055
	NAPHTHENES			
48.9	Cyclopentane	C5H10	0.0003	0.0001
72.2	Methylcyclopentane	C6H12	0.0008	0.0003
81.1	Cyclohexane	C6H12	0.0009	0.0003
101.1	Methylcyclohexane	C7H14	0.0027	0.0012
	TOTAL		1.0000	1.0000

The above hexanes plus values are based upon a measured mass fraction and a calculated mole fraction, and assume a total hydrocarbon recovery from the chromatographic system.

CORE LABORATORIES-CANADA LTD.

COMPANY Technical University of Nova Scotia
LOCATION
SAMPLED FROM Oil From Concentrate

FILE 70380-86-18
DATE 1986 01 06

Analysis to C30+

Boiling Point Range (C)	Component	Carbon Number	Mole Fraction	Mass Fraction
-161.7	Methane	C1	0.0000	0.0000
- 88.9	Ethane	C2	0.0000	0.0000
- 42.2	Propane	C3	0.0000	0.0000
- 11.7	Iso Butane	C4	0.0000	0.0000
- 0.6	Normal Butane	C4	0.0000	0.0000
27.8	Iso Pentane	C5	0.0002	0.0000
36.1	Normal Pentane	C5	0.0018	0.0006
36.1- 68.9	Hexanes	C6	0.0056	0.0020
68.9- 98.3	Heptanes	C7	0.0309	0.0130
98.3-125.6	Octanes	C8	0.0374	0.0178
125.6-150.6	Nonanes	C9	0.0325	0.0174
150.6-173.9	Decanes	C10	0.0372	0.0221
173.9-196.1	Undecanes	C11	0.0563	0.0368
196.1-215.0	Dodecanes	C12	0.0602	0.0429
215.0-235.0	Tridecanes	C13	0.0957	0.0738
235.0-252.2	Tetradecanes	C14	0.0871	0.0723
252.2-270.6	Pentadecanes	C15	0.0675	0.0600
270.6-287.8	Hexadecanes	C16	0.0488	0.0462
287.8-302.8	Heptadecanes	C17	0.0366	0.0368
302.8-317.2	Octadecanes	C18	0.0325	0.0346
317.2-330.0	Nonadecanes	C19	0.0372	0.0418
330.0-344.4	Eicosanes	C20	0.0274	0.0324
344.4-357.2	Heneicosanes	C21	0.0256	0.0317
357.2-369.4	Docosanes	C22	0.0241	0.0313
369.4-380,0	Tricosanes	C23	0.0228	0.0310
380.0-391.1	Tetracosanes	C24	0.0196	0.0277
391.1-401.7	Pentacosanes	C25	0.0174	0.0257
401.7-412.2	Hexacosanes	C26	0.0161	0.0246
412.2-422.2	Heptacosanes	C27	0.0145	0.0230
422.2-431.7	Octacosanes	C28	0.0122	0.0201
431.7-441.1	Nonacosanes	C29	0.0113	0.0192
441.1 PLUS	Triacontanes Plus	C30+	0.0739	0.1863
	AROMATICS			
80.0	Benzene	C6H6	0.0021	0.0007
110.6	Toluene	C7H8	0.0109	0.0042
136.1-138.9	Ethylbenzene, p + m-Xylene	C8H10	0.0141	0.0063
144.4	o-Xylene	C8H10	0.0118	0.0052
168.9	1,2,4 Trimethylbenzene	C9H12	0.0139	0.0070
	NAPHTHENES			
48.9	Cyclopentane	C5H10	0.0006	0.0002
72.2	Methylcyclopentane	C6H12	0.0048	0.0017
81.1	Cyclohexane	C6H12	0.0050	0.0018
101.1	Methylcyclohexane	C7H14	0.0044	0.0018
	TOTAL		1.0000	1.0000

The above hexanes plus values are based upon a measured mass fraction and a calculated mole fraction, and assume a total hydrocarbon recovery from the chromatographic system.